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Luis Eduardo Esteves

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THÈSE

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Luis Eduardo ESTEVES

Thèse dirigée par **Catherine LOCATELLI**, Chargée de recherche
CNRS, Université Grenoble Alpes.

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Petroleum Frontier Zones: A Study of the American and Argentinian cases

Thèse soutenue publiquement le **03/mai/2021**,
devant le jury composé de:

Madame, Catherine LOCATELLI

Chargée de recherche CNRS, Université Grenoble Alpes, (Directrice de
thèse)

Madame, Sandrine MICHEL

Professeur, Université de Montpellier 1 (Rapporteur et Président du jury)

Monsieur, Helder Queiroz PINTO JUNIOR

Professor associé 4 de la UFRJ - Universidade Federal do Rio de Janeiro
(Rapporteur)

Monsieur, Sylvain ROSSIAUD

Maître de conférences Université Grenoble Alpes (Examinateur)

Monsieur, Jacques PERCEBOIS

Professeur émérite Université Montpellier (Examinateur)



Résumé - Zones de Frontières de gaz naturel : une étude du US et de l'Argentine sur les réservoirs non-conventionnels

La production de pétrole et de gaz naturel (O&G) aux États-Unis (US) a fortement augmenté depuis le début des années 2000 sur la base du développement des réservoirs non conventionnels et en particulier ceux de schiste. Ce développement compte tenu de son ampleur a été qualifié de « révolution » et a eu une influence considérable sur le marché des O&G. Cette augmentation remarquable de la production de schiste permet aux États-Unis de se positionner aujourd'hui comme le premier producteur mondial de gaz naturel. Les déterminants de cette croissance rapide ont fait l'objet de nombreuses études qui visent à déterminer les principales variables permettant une exploitation commerciale sur grande échelle des réservoirs non conventionnels. Il s'agit en particulier des facteurs susceptibles de reproduire cette « révolution » dans d'autres régions du monde. Ces interrogations sont essentielles quant à la dynamique future des marchés du gaz naturel. Le développement des réservoirs non conventionnels jette également un éclairage sur les possibilités de développer au-delà des non conventionnels les hydrocarbures des zones qualifiées de zones frontalières. L'exploitation commerciale des réservoirs de schiste appartient à cette catégorie.

Pour ce faire, cette thèse définit d'abord les zones frontalières de O&G en fonction de leurs caractéristiques économiques. Ce sont des zones ayant des risques élevés, des coûts élevés et un impliquant un défi technologique majeur pour les mettre en production. Ces trois variables constituent des contraintes pour leur mise en production. Par conséquent, l'objectif de cette thèse a été de déterminer les facteurs qui ont permis de lever les trois principales contraintes identifiées comme limitant leur développement. À partir des caractéristiques des zones frontalières et d'une approche basée sur la théorie évolutionniste et l'institutionnalisme historique un cadre d'analyse a été défini afin d'appréhender et de caractériser les facteurs qui ont déterminé le développement des zones frontalières de O&G. Ce cadre d'analyse a été appliqué aux États-Unis et à l'Argentine.

L'étude du cas américain est un point de référence central car il est actuellement le seul exemple d'exploitation commerciale massive du gaz de schiste à l'échelle mondiale. L'étude du cas argentin a pour objectif d'affiner, de classer et de systématiser les conclusions tirées sur le cas américain quant aux principaux déterminants du développement des zones frontalières.

L'analyse des deux cas conduit à trois conclusions principales. Premièrement, les deux pays ont été confrontés à des problèmes d'offre du gaz naturel ce qui a pu conduire à la mise en œuvre des efforts du gouvernement visant à améliorer la rentabilité de l'exploration et de la production de gaz naturel. Deuxièmement, l'exploitation des réservoirs de schiste non conventionnels est sensible aux prix du gaz naturel. Par conséquent, on assiste à des changements institutionnels successifs dans le cadre réglementaire qui ont graduellement diminué la capacité du gouvernement à définir les prix du gaz naturel notamment à les baisser pour des enjeux sociaux. Les efforts du gouvernement mis en œuvre ont largement été centrés sur des soutiens financiers accordés aux producteurs de gaz naturel, ce qui a eu une influence positive sur le développement des réservoirs non conventionnels. Troisième, il existe une coopération entre les secteurs public et privé pour accélérer l'adaptation technologique. On peut dès lors définir une courbe d'apprentissage dans les deux cas (*Barnett shale* pour les États-Unis et la région de *Vaca Muerta* pour l'Argentine) avec deux étapes bien délimitées. Les caractéristiques de chaque étape de la courbe d'apprentissage correspondent à la description de Dosi (1982) du processus graduel d'introduction d'une avancée technologique et de la structure du marché (principalement la présence d'entreprises ayant une aversion au risque moindre dans la première phase et la concurrence dans la deuxième phase).

Abstract - Natural gas frontier zones: a study of the US and Argentinian unconventional reservoirs cases

The oil and natural gas production in the United States (US) has increased sharply since the early 2000s on the basis of unconventional reservoirs' development and, in particular those of shale. Given the huge scale of this development, it has been called a 'revolution', substantially influencing the O&G market. This remarkable increase in shale production allows the US to position itself today as the world's leading producer of natural gas. The determinants of this rapid growth have been the subject of numerous studies aimed at determining the main variables allowing large-scale commercial exploitation of unconventional reservoirs. These are in particular the factors that could reproduce this 'revolution' in other countries. These questions are essential for the future dynamics of natural gas markets. The development of unconventional reservoirs also sheds light on the possibilities of developing hydrocarbons in areas qualified as frontier zones beyond unconventional ones. The commercial exploitation of shale reservoirs fits into this category.

To reach our objective, this thesis first defines the O&G frontier zones according to their economic characteristics. These areas are featured by high risks, high costs and a technological challenge to achieve its commercial exploitation. These three variables constitute constraints for their production. Therefore, the objective of this thesis was to determine the factors that allowed to overcome the three main constraints identified as limiting their development. From the characteristics of the frontier zones and from an approach based on both, evolutionary theory and historical institutionalism, we defined an analytical framework in order to understand and characterize the factors determining the development of O&G frontier areas based on unconventional shale reservoirs. This analytical framework has been applied to the cases of the US and Argentina

The US case study is a central point of reference as it is currently the only example of massive commercial exploitation of shale gas on a global scale. The objective of the Argentine case study is to refine, classify and systematize the conclusions drawn from the US case regarding the main determinants of the development of frontier zones.

The analysis of the two cases leads to three main conclusions. First, the two countries faced natural gas supply problems, leading government to launch efforts aiming to improve the profitability of natural gas exploration and production. Second, the exploitation of unconventional shale reservoirs is sensitive to natural gas prices. Consequently, we observe successive institutional changes in the regulatory framework which gradually prevent government to define natural gas prices, in particular to lower them for social reasons. The government's efforts have largely focused on financial support for natural gas producers, which has had a positive influence on the development of unconventional reservoirs. Third, there is cooperation between the public and private sectors to accelerate technological adaptation. Concerning the technological adaptation, we identify a learning curve in both cases (Barnett shale for the US and the *Vaca Muerta* region for Argentina) with two well-defined stages. The characteristics of each stage of the learning curve correspond to Dosi (1982) description of the gradual process of introducing technological advancement and the market structure (mainly the presence of firms with lower risk aversion in the first phase and competition in the second phase).

RÉSUMÉ

Cette thèse se propose d'analyser les déterminants du développement des zones frontières O&G à partir d'une étude des réservoirs de schiste non conventionnels. Nous avons divisé cette thèse en trois chapitres principaux ajoutés. Le premier chapitre est centré sur la définition des zones frontières ainsi que sur les perspectives O&G. Le deuxième chapitre porte sur le cadre analytique de notre thèse. Celle-ci est basée principalement sur la théorie évolutionniste et accessoirement sur l'institutionnalisme historique. Sur la base de ces appuis théoriques, nous étudions le cas américain de la région des gaz de schiste de Barnett, en étant attentifs aux déterminants directs et indirects du développement des zones frontières. Le troisième chapitre analyse le cas argentin de la région de Vaca Muerta. Il permet de conclure que les déterminants de l'évolution de cette zone frontière sont similaires à ceux identifiés sur le cas américain.

Dans un premier temps pour préciser notre objet d'étude, nous avons défini les caractéristiques des zones frontières. Nous avons passé en revue trois perspectives O&G, en étant attentif à l'accélération du taux de déclin dû au changement structurel des caractéristiques des gisements (participation croissante des réservoirs non conventionnels et des réservoirs conventionnels plus petits). Nous avons conclu que même compte tenu d'une stabilité de la consommation d'énergie associée à un remplacement rapide des O&G par d'autres types d'énergie, il est nécessaire de développer des champs O&G supplémentaires. En d'autres termes, en comparant les taux de déclin avec la vitesse à laquelle la demande O&G diminue, les taux de déclin sont supérieurs, nécessitant des investissements supplémentaires sur les champs O&G. Cet élément démontre que même en considérant un scénario de transition énergétique rapide vers des énergies à faible teneur en carbone, il existe des opportunités pour répondre à la demande future de O&G grâce au développement de zones frontières par les gouvernements intéressés.

Nous avons défini la zone frontière par ses coûts élevés, ses risques élevés et le défi technologique pour atteindre leur exploitation commerciale. Notre définition de la zone frontière peut englober à la fois des réservoirs conventionnels ou non conventionnels. Cette définition est générique, exigeant un affinement pour délimiter les instruments et mécanismes favorisant leur exploitation commerciale. Dans ce cas, à partir de cette définition générique, nous nous sommes concentrés sur les risques O&G, en cherchant à différencier les zones frontières des autres zones O&G. Nous avons partagé les risques dans deux grandes catégories : les risques de marché et les risques E&P.

Les zones frontières diffèrent des autres zones O&G en raison des risques E&P partagés sur les plans géologique et technico-économique. Concernant les zones frontières liées à des réservoirs de schiste, les risques géologiques, principalement liés à l'existence des ressources, sont quasi inexistantes, ce qui conduit cette thèse à se concentrer sur les risques techniques et économiques. En outre, du point de vue de l'investisseur, l'absence d'activité E&P est le principal facteur de motivation du risque élevé dans les zones frontières, limitant l'implication des investisseurs privés dans un premier temps. Dans ce cas, l'accélération de l'exploitation des zones frontières exige un effort gouvernemental pour faire face à leurs caractéristiques, principalement l'absence de connaissances suffisantes.

Dans ce contexte, cette thèse s'est concentrée sur la dynamique antérieure à la « révolution » du schiste, en adoptant un point de vue rétrospectif. Ce point de vue nous a permis d'identifier les déterminants directs et indirects conduisant à l'exploitation des réservoirs de schiste des zones frontières aux États-Unis. Nous avons comparé cette expérience avec celle de l'Argentine.

Notre enquête sur ces déterminants concorde avec d'autres auteurs selon lesquels l'environnement institutionnel particulier et l'adaptation technologique sont essentiels pour expliquer la réussite de l'exploitation commerciale (J. Cooper, Stamford et Azapagic 2016; Zakaria 2019; Dale 2015; GWPC 2009; IEA 2012; Kuuskraa et Guthrie 1995; Stevens 2010; Wang et Krupnick 2013; Anderson 2013; Harper 2008). Dans notre perspective économique, les deux facteurs atténuent les risques caractéristiques des zones frontières.

D'une part, la hausse des prix du gaz naturel a amélioré la rentabilité des zones frontalières, atténuant les risques économiques. L'augmentation des prix du gaz naturel est obtenue grâce à deux instruments. Premièrement, à travers une réorganisation institutionnelle progressive du cadre réglementaire qui façonne une trajectoire de libéralisation du marché (permettant aux prix de refléter les interactions entre l'offre et la demande). Deuxièmement, grâce à un soutien financier de l'État, qui, du point de vue de l'investisseur, équivaut à une augmentation des prix du gaz naturel.

De l'autre part, l'accélération du progrès technologique se fait grâce à un instrument associé à deux mécanismes. L'instrument est une coopération entre les secteurs public et privé, pendant que les mécanismes sont une courbe d'apprentissage et l'aversion au risque de l'entreprise.

Nos analyses de cas d'étude ont permis de mettre en évidence les particularités des pays concernés : la manière dont celles-ci ont façonné la mise en œuvre des instruments et des

mécanismes nécessaires au développement des gaz de schiste. L'association de tous ces éléments délimite notre objet d'étude : l'exploitation commerciale des zones frontalières à partir de l'analyse des réservoirs de schiste non conventionnels. Pour structurer l'analyse de nos deux études de cas, nous avons conçu un cadre analytique structuré à la fois sur les caractéristiques des zones frontalières et notre support théorique basé sur deux grandes approches économiques : l'institutionnalisme historique et la théorie évolutionniste.

L'approche de l'institutionnalisme historique nous a permis d'analyser la dynamique institutionnelle du cadre réglementaire dans une perspective à long terme. Dans ce contexte, nous nous sommes concentrés sur la direction du changement au lieu de scruter chaque réforme, obtenant dans les deux cas (États-Unis et Argentine) une trajectoire laissant à la dynamique du marché la détermination du prix du gaz naturel. Cette trajectoire représente une hausse des prix du gaz naturel en tête de puits, reflétant le resserrement entre l'offre et la demande dans les deux pays. De plus, du point de vue de l'investisseur, un autre élément qui reflète une augmentation de la rentabilité de ces opérations est le soutien financier. Le soutien financier américain est opérationnalisé par des crédits d'impôt et une hausse des prix du gaz naturel (jusqu'à la libéralisation complète des prix). Le soutien financier argentin est opérationnalisé par un prix minimum garanti pour le gaz naturel.

Nous avons conclu que les deux instruments atténuent les risques économiques des zones frontalières en augmentant les prix du gaz naturel. Alors que le premier est un déterminant indirect, adopté par les gouvernements sans intention de développer des zones frontalières, le second est un déterminant direct. Dans le cas des États-Unis, le soutien financier se concentre sur les zones à coût élevé, y compris les réservoirs de schiste non conventionnels. En Argentine, le gouvernement fait évoluer progressivement son soutien financier en orientant le prix minimal garanti de la production supplémentaire de gaz naturel (indépendamment du type de réservoirs) exclusivement à l'exploitation des réservoirs de schiste non conventionnels.

La théorie évolutionniste permet à cette thèse d'analyser le processus complexe d'introduction d'un progrès technologique dans une économie capitaliste. Dans les deux cas, l'atténuation des risques technologiques passe par une accélération de l'adaptation technologique. Nous soulignons que l'Argentine bénéficie du développement antérieur réalisé aux États-Unis, principalement l'association réussie entre la fracturation hydraulique (HF) basée sur la méthode « slick-water fracturing » (SWF) et le forage horizontal. Malgré cet avantage direct des réalisations précédentes du schiste de Barnett, l'adaptation technologique en Argentine est caractérisée par des risques élevés.

Sur la base de la littérature évolutionniste, cette thèse a identifié deux aspects principaux à étudier. Premièrement, la mise en œuvre des « focusing forces » entraînant l'accélération de la trajectoire technologique. Dans ce cas, selon Rosenberg (1976), les prix (dans cette thèse, les prix du gaz naturel) sont fondamentaux pour stimuler le développement technologique. Cependant, ils sont insuffisants pour offrir une élucidation complète du phénomène, principalement la séquence et le timing de l'avancée technologique. Ainsi, cette thèse identifie deux éléments comme des « focusing forces » pertinentes qui dirigent et accélèrent le développement technologique : les problèmes d'approvisionnement en gaz naturel (Rosenberg 1976) ; et le rôle de l'État (Dosi et Nelson 2013 ; Dosi 1982). Dans ce contexte, l'analyse du contexte national s'intéresse principalement aux problèmes d'approvisionnement en gaz naturel (sous forme de pénuries ou autres limitations) et de la réaction gouvernementale qui en découle.

Deuxièmement, deux mécanismes accélèrent l'adaptation technologique, atténuant les risques technologiques liés à l'introduction du forage HF et horizontal sur les réservoirs non conventionnels : une courbe d'apprentissage et l'aversion au risque de l'entreprise. La courbe d'apprentissage représente le mécanisme d'appropriation pour les entreprises introduisant le progrès technologique dans l'économie capitaliste, englobant plusieurs dimensions telles que : l'heuristique de la recherche, sa cumulativité et l'apprentissage par l'action. Ainsi, la courbe d'apprentissage englobe le processus multiforme entre les entreprises et les marchés lors de l'introduction des progrès technologiques dans le système économique.

La théorie évolutionniste étudie l'environnement incertain lié à l'introduction et à la sélection des avancées technologiques à travers les marchés, mettant en évidence la pertinence d'agents hétérogènes. L'incertitude est due à l'absence de garanties, ex ante, que l'engagement dans un développement technologique spécifique fournisse les résultats positifs attendus associés à la sélection ex post sur les marchés. L'association de ces éléments génère un environnement incertain pour les entreprises qui s'engage à l'introduction d'une avancée technologique, caractérisé par des risques élevés. Dans ce contexte, les entreprises ayant une aversion pour le risque plus faible (ou un appétit pour le risque plus élevé) sont plus enclines à s'engager dans le processus de courbe d'apprentissage dans un investissement à haut risque pour capturer plus de profits à l'avenir.

Sur la base de notre cadre analytique (présenté dans la figure 5, chapitre 2), cette thèse a analysé les deux expériences concernant le développement de zones frontières basées sur des réservoirs de schiste non conventionnels aux États-Unis et en Argentine. De cette analyse, nous

concluons que le développement de ces zones frontières présentait trois éléments principaux. Premièrement, les pays analysés sont confrontés à des problèmes d'approvisionnement en gaz naturel, déclenchant un effort gouvernemental pour les surmonter. Deuxièmement, nous pouvons partager ces efforts sur deux éléments, un soutien financier (augmentation de la rentabilité des zones frontières) et une coopération avec des entreprises privées (accélération de l'introduction technologique). Troisièmement, les entreprises qui souhaitent s'engager dans une adaptation technologique incertaine sont moins averses au risque (principalement représentées dans le secteur O&G par des entreprises indépendantes). Elles s'engagent dans une courbe d'apprentissage pour capturer des profits plus élevés à l'avenir. Dans notre perspective, les gouvernements peuvent accélérer ce processus grâce à une coopération directe avec le secteur privé.

Une comparaison entre les pays analysés nous a permis de conclure que les deux pays étaient confrontés à un problème d'approvisionnement. Alors que les États-Unis sont confrontés à deux pénuries successives de gaz naturel au milieu de deux chocs pétroliers, l'Argentine est confrontée à une crise d'approvisionnement aux impacts sociaux et économiques. Dans le cas américain, la demande croissante associée à une offre insuffisante conduit le pays à des pénuries pendant les hivers 1975-76 et 1977-78. De même, en Argentine, l'augmentation substantielle de la demande l'emporte sur l'offre, conduisant le pays à limiter la demande afin de dépasser la pénurie. Les deux pays ont mis en œuvre un certain nombre de mesures pour répondre à ces problèmes d'approvisionnement. Initialement, elles ne ciblaient pas spécifiquement les zones frontières en développement basées sur des réservoirs non conventionnels. Mais elles en atténuent toutefois les risques.

Dans les deux pays, le changement institutionnel façonne une trajectoire à long terme conduisant à une formation des prix basée sur la dynamique entre l'offre et la demande. La formation des prix passe progressivement d'une détermination gouvernementale à une interaction entre l'offre et la demande. Dans la trajectoire de long terme des États-Unis, des réformes successives préparent cette dynamique dès les années 1990. Cette formation des prix permet aux prix du gaz naturel de refléter le resserrement entre l'offre et la demande, augmentant les prix du gaz naturel avant la « révolution » du schiste.

Le contexte particulier argentin empêche une libéralisation complète de la formation des prix jusqu'en 2020. Il diffère principalement de celui des États-Unis en raison des crises économiques successives aux effets sociaux importants. Ce contexte spécifique conduit le gouvernement argentin à subventionner en permanence la consommation de gaz naturel, en

limitant la hausse des prix (reflétant le resserrement entre l'offre et la demande). Il cherche ainsi à réduire les effets redistributifs de la hausse des prix du gaz naturel.

Dans les deux pays, la hausse des prix issue de cette nouvelle dynamique de marché n'a pas ciblé le développement de réservoirs non conventionnels. Cependant, elle atténue les risques économiques spécifiquement liés aux zones frontalières.

A l'inverse de la hausse des prix issue de la libéralisation de la formation des prix du gaz naturel, les aides financières octroyées par l'Etat sont une mesure directe visant à développer les zones frontalières. Dans le cas des États-Unis, le gouvernement mobilise des subventions fiscales (qui durent jusqu'en 2002) et des prix plus élevés du gaz naturel (pendant la période de contrôle des prix) pour accélérer l'exploitation des zones à coûts élevés (y compris les réservoirs de schiste non conventionnels). Dans le cas argentin, le gouvernement crée des plans énergétiques pour garantir un prix minimum du gaz naturel. Du point de vue de l'investisseur, ces mesures fonctionnent comme un soutien financier aux activités E&P dans les zones frontalières.

À l'instar du cas américain, le gouvernement argentin crée un soutien financier pour les entreprises qui se lancent dans l'exploitation de réservoirs non conventionnels. Ce soutien financier est opérationnalisé par des prix garantis plus élevés visant à augmenter la production nationale de gaz naturel à partir de tous les réservoirs. Néanmoins, les résultats positifs de l'exploitation non conventionnelle conduisent l'Etat à réserver ces prix garantis aux seuls réservoirs de schiste.

Les deux éléments, la réforme des prix et les prix garantis débouchent sur des augmentations des prix du gaz naturel. Associés aux aides financières de l'Etat, ils atténuent les risques économiques des zones frontalières basées sur des réservoirs de schiste non conventionnels. Les deux pays, les États-Unis et l'Argentine, mobilisent ces instruments pour développer directement (soutien financier) et indirectement (réorganisation institutionnelle) les réservoirs non conventionnels.

Un autre instrument mobilisé par les deux gouvernements est une coopération directe avec des entreprises engagées dans l'introduction de technologies (dans ce cas, HF et forage horizontal) sur des réservoirs non conventionnels. Cet instrument est un effort direct pour développer des réservoirs non conventionnels, en se concentrant sur l'accélération de l'adaptation technologique, atténuant ainsi les risques technologiques des zones frontalières.

Dans le cas des États-Unis, le gouvernement accélère l'introduction technologique grâce à deux mesures principales. Premièrement, il délimite le potentiel de l'exploitation non conventionnelle des réservoirs, identifiant des sources d'énergie nationales supplémentaires. En second lieu, associé au secteur privé, il définit la trajectoire technologique relative à l'adaptation des deux méthodes d'extraction (HF et forage horizontal) pour libérer le gaz naturel des réservoirs non conventionnels. Dans ce cas particulier, le gouvernement a fourni des fonds pour tester les deux technologies sur des réservoirs non conventionnels, débattant avec des acteurs privés des techniques les plus adaptables associées à d'autres technologies nécessaires pour atteindre l'exploitation commerciale de ces ressources. Pour atteindre cet objectif, le gouvernement crée plusieurs institutions relais pour réaliser des progrès technologiques en adaptant et en créant des technologies à des réservoirs non conventionnels.

Dans le cas argentin, il existe une coopération entre les secteurs public et privé, mais de nature différente de celle des États-Unis, principalement en raison du défi technologique présenté dans les deux cas. Alors que les États-Unis délimitent et font progresser les technologies de pointe en matière de gaz de schiste, l'Argentine bénéficie de ces progrès. Dans ces conditions, la coopération repose sur l'association entre le « national oil company » (NOC) et des entreprises privées, principalement « international oil company » (IOC), à travers des joint-ventures partageant les coûts de développement dans la région de Vaca Muerta. Cette coopération entre YPF et des entreprises privées est principalement centrée sur les IOC, recherchant à la fois des fonds pour développer la zone et des partenaires pour partager les risques. Ceci a pu conduire à une accélération de l'adaptation technologique dans la région.

Ainsi, cette thèse démontre en accord avec d'autres auteurs que le développement technologique en Argentine bénéficie des progrès antérieurs des États-Unis. Ceci a constitué un avantage par rapport aux conditions initiales américaines (Wang et Krupnick 2013, 32–33; Morrow 2014, 6; IEA 2019, 378). Après l'expérience américaine et la « révolution » du schiste, les zones frontières basées sur des réservoirs non conventionnels présentent un défi technologique intégrant l'adaptation des technologies au contexte géologique. Néanmoins, il s'agit toujours d'un défi technologique important qui représente des risques élevés pour les entreprises qui s'engagent à introduire ces avancées pour tirer les bénéfices futurs des réalisations de la courbe d'apprentissage. Dans le cas argentin, ces risques technologiques élevés sont partagés entre le NOC et les IOC. Ainsi, les deux pays atténuent directement les risques technologiques associés aux zones frontières en coopérant avec le secteur privé pour améliorer l'adaptation technologique.

Cette thèse identifie et analyse le fonctionnement de deux facteurs importants de la théorie évolutionniste : la courbe d'apprentissage et l'aversion au risque des entreprises. Nous avons basé notre étude de la courbe d'apprentissage sur les pics de productivité des puits comme facteurs pertinents pour centrer nos analyses sur le marché, l'environnement et les entreprises impliquées dans l'introduction technologique. L'utilisation des pics de productivité des puits a permis à cette thèse de partager la courbe d'apprentissage en deux étapes. Dans les deux pays, la première étape de la courbe d'apprentissage est caractérisée par l'adaptation du HF dans les puits verticaux. Alors que dans le cas américain cette adaptation technologique se produit dans les réservoirs de schiste, dans le cas argentin, elle se concentre sur les réservoirs compacts. La deuxième étape de la courbe d'apprentissage correspond à une association de la méthode HF avec des puits horizontaux dans des réservoirs de schiste non conventionnels.

En examinant chaque étape de la courbe d'apprentissage et la structure du marché, nous avons trouvé une autre similitude remarquable entre les cas. La première étape de la courbe d'apprentissage est dirigée par une société indépendante, notamment moins averse au risque (ou avec un appétit pour le risque plus élevé) que les autres sociétés O&G. Ce leadership diminue progressivement dans la deuxième étape de la courbe d'apprentissage en fonction du nombre croissant d'entreprises exploitant la zone. Dans le cas des États-Unis, une plus grande société indépendante fusionne avec le leader et, simultanément, d'autres sociétés indépendantes entament un processus pour rattraper les réalisations du leader. En Argentine, YPF (la compagnie nationale) rachète les deux entreprises leaders, officialisant plusieurs joint-ventures avec les compagnies pétrolières internationales pour exploiter la région de Vaca Muerta. Dans le même temps d'autres entreprises accroissent leur participation dans l'exploitation de cette région. Dans les deux cas, on peut supposer que cette participation croissante d'autres entreprises représente les retombées de l'accumulation des connaissances issues des réalisations de la courbe d'apprentissage dans les deux cas.

Selon Dosi (1982), les avancées technologiques dans un système économique génèrent une dynamique spécifique suivant deux phases principales. Concernant cette dynamique, l'analyse de l'introduction du forage HF et horizontal dans les deux pays, les États-Unis et l'Argentine, révèle un parallèle intéressant avec la théorie évolutionniste. Alors que dans la première phase (émergence) un acteur doit accepter de prendre des risques pour introduire l'avancée technologique, la seconde phase (maturité) est caractérisée par une compétition oligopolistique. A partir de l'examen de notre périodisation de la courbe d'apprentissage de ces deux régions (schiste de Barnett et Vaca Muerta), nous observons ces deux phases distinctes. La première intégrant une entreprise leader (rôle joué par des entreprises indépendantes,

notamment moins averses au risque), et la seconde se caractérise par une concurrence croissante entre les entreprises. Concernant la deuxième étape de la courbe d'apprentissage, il est pertinent de mettre l'accent sur la consolidation de l'exploitation non conventionnelle. Alors qu'aux États-Unis, la concurrence croissante est obtenue par le biais de grandes sociétés indépendantes, en Argentine, il faut noter la participation croissante des IOCs.

Du point de vue économique, nous sommes d'accord avec d'autres auteurs pour dire qu'un environnement particulier associé à une courbe d'apprentissage est le déterminant pertinent pour expliquer la production croissante à partir de réservoirs non conventionnels dans les deux pays. Néanmoins, cette thèse détaille l'environnement particulier de chaque pays, examinant les réalisations de la courbe d'apprentissage et ses multiples retours d'expérience avec l'environnement, fournissant des leçons supplémentaires aux gouvernements intéressés par le développement des zones frontières O&G.

Nous soulignons qu'une contingence particulière pousse les pays à augmenter la production nationale. Pour atteindre cet objectif, le gouvernement repense progressivement son environnement en mobilisant trois instruments principaux (les reformulations du cadre réglementaire, le soutien financier et la coopération avec le secteur privé) pour développer directement ou indirectement des réservoirs non conventionnels. Malgré la mobilisation de ces instruments, nos études de cas démontrent la nécessité pour les entreprises moins averses au risque de s'engager dans une courbe d'apprentissage incertaine, déclenchant la première étape. Dans le cas argentin, il est intéressant d'observer que les opérations initiales se concentrent sur des réservoirs compacts, notamment moins chers que ceux de schiste. L'association de ces trois instruments et de ces deux mécanismes, dans notre étude de cas, a mis en évidence les éléments essentiels pour atteindre l'exploitation commerciale des zones frontières à partir de réservoirs de schiste non conventionnels.

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Acronym List:

BP	British Petroleum
DoE	Department of Energy
E&P	Exploration and production
EIA	Energy Information Administration
ENARGAS	<i>Ente Nacional Regulador del Gas</i>
ERDA	Energy Research and Development Administration
FERC	Federal Energy Regulatory Commission
FPC	Federal Power Commission
GDP	Gross Domestic Product
GRI	Gas Research Institute
GSI	<i>Golfo de San José</i>
GWPC	Ground Water Protection Council
GyP	<i>Gas y Petroléo Neuquén</i>
HF	Hydraulic fracture
IAE	Instituto Argentino de la Energía
IAPG	Instituto Argentino del Petroleo y del Gas
IEA	International Energy Agency
IEASA	<i>Integración Energética Argentina S.A.</i>
IEO	Independent Evaluation Office
IMF	International Monetary Fund
IOC	International Oil Companies
ISI	Import Substitution Industrialization
LNG	Liquefied Natural Gas
LSF	Light Sand Fracture
MEG	Mercado Electrónico de Gas
NAS	National Academy of Sciences
NBP	National Balancing Point
NGA	Natural Gas Act
NGPA	Natural Gas Policy Act
NGWDA	Natural Gas Wellhead Decontrol Act

NOC	National Oil Company
NPC	National Petroleum Council
NPD	Norwegian Petroleum Directorate
O&G	Oil and Natural Gas
OCS	Outer Continental Shelf
OECD	Organisation for Economic Co-operation and Development
OPEC	Organisation of the Petroleum Exporting Countries
R&D	Research and Development
RRC	Railroad Commission of Texas
SEDS	State Energy Data System
SMPs	Special Marketing Programs
SWF	Slick Water Fracturing
UGRP	Unconventional Gas Research Program
UK	United Kingdom
URR	Ultimately Recoverable Resources
US	United States
USGS	United States Geological Survey
YPF	<i>Yacimientos Petroliferos Fiscales</i>

Units:

MW	Megawatt
Kcm/d	Thousand cubic meters per day
Mbbl/d	Million barrels per day
Bcm/d	Billion cubic meters day
Tcm/d	Trillion cubic meters day

Introduction

The production of oil and natural gas (O&G) in the United States (US) has been increasing since 2000, based on unconventional reservoirs' exploitation. The growing production has been changing the US status from a net energy importer to a net exporter, creating a 'revolution' with considerable influence in the O&G market¹. Between 2007 and 2018, the gross production of natural gas from unconventional shale reservoirs in the US multiplied almost twelve times, from 154 million cubic meters per day (Mcm/d) to 1 827 Mcm/d. Considering its share in the total production, it increases from 8% in 2007 to 63.5% in 2018 (EIA 2020c). This impressive increase in unconventional shale output propelled the country to become the largest natural gas producer. Additionally, the US become one of the three largest exporters of Liquefied Natural Gas (LNG), with a total capacity forecasted around 598 Mcm/d in 2025, of which 180 Mcm/d are operational in 2019², representing 11% of the whole world liquefaction capacity in 2019 (GIIGNL 2020, 40–41). Due to the speed at which the production increased, it is common to speak of a shale gas 'revolution' in the US.

The determinants of this rapid growth in production from unconventional shale reservoirs have been the subject of numerous studies (J. Cooper, Stamford, and Azapagic 2016; Zakaria 2019; Dale 2015; GWPC 2009; IEA 2012; Kuuskraa and Guthrie 1995; Stevens 2010; Wang and Krupnick 2013). The objective is to define the variables determining the commercial exploitation of unconventional reservoirs, highlighting both opportunities and constraints for similar developments in other countries with significant resources in this area like China, Argentina, Algeria, Canada, Mexico, Australia, South Africa, Russia, and Brazil (EIA 2013, 10). This is one of the most critical questions regarding the further dynamics of natural gas markets. Indeed, the acceleration in extraction from unconventional reservoirs will shape the global natural gas supply's future profile.

¹ Taking in perspective, from a previous position of the larger net importer of energy in the world, the US will become a net exporter after 2020, mainly driven by the shale 'revolution' (EIA 2020b, 12). Since 1953 the US increased their imports of energy, mainly O&G, becoming the largest importer of both fuels in the world until the 'revolution' outbreaks in 2000. After the 'revolution', the national production consistently grows. Firstly, the 'revolution' increased the natural gas production but quickly spreads the extractive technics for oil reservoirs, also increasing its production. Thus, the participation of the unconventional reservoirs source increases, gradually reducing the US' necessity of imports to supply the domestic market. It is noteworthy that in 2017, the US becomes a net exporter of natural gas and in 2020, the US Energy Information Administration (EIA) outlooks that the country will become a net oil exporter (EIA 2020b, 12).

² The original data are in million tons per annum (MTPA), achieving the value of 158 MTPA and 48.3 MTPA.

Beyond the 'revolution' effects, the commercial exploitation of unconventional reservoirs also shed light on issues related to O&G areas named frontier zones. The exploitation of unconventional shale reservoirs belongs to this category. This thesis defined O&G frontier zones based on its features from our economic perspective, being their features: high risks, high costs, and a technological challenge. Among the differences between a frontier zone and other O&G zones, its low level of exploration and production activities influence the investor's capacity to delimit risks, rising its magnitude, being another remarkable feature of O&G frontier zones.

This thesis' primary objective is to identify the factors determining the development of a frontier zone based on unconventional shale reservoirs. Based on both frontier zones features and our theoretical support from economic theories, this thesis delineates an analytical framework allowing to examine our object of study. One of the biggest challenges is distinguishing between the essentiality among the factors, in other terms, factors strictly necessary and other influencing but not determining the frontier zone development. All these factors are based on economic, institutional, and political characteristics.

To achieve the thesis objective, we analyze two cases, the US and Argentina. The US study is mandatory since it is currently the single example of massive commercial exploitation of unconventional shale gas globally. Relatively less studied than the US case, the choice of Argentina is justified by the fact that it is the country with the most promising areas to exploit unconventional shale reservoirs in the world³ (IEA 2019; Cameron et al. 2018; EIA 2020b). Since 2014, there has been a constant increase in natural gas production in Argentina, with an average annual growth rate of almost 4%, mainly based on extractions from unconventional reservoirs in the *Vaca Muerta* region. Observing the growth of natural gas output from unconventional reservoirs, since 2014, it increases at an average rate of 15.2% per year. Thus, the Argentinean case should refine, classify and systematize the conclusions relating to the essential factors determining the development of frontier zones based on unconventional reservoirs. In our perspective, the essential factors determining the frontier zones development has been identifying only taking the US experience, enhancing the relevance of our comparative analysis.

³ Taking the global perspective, only four countries in the world produce from shale or tight formations: US, Canada, China, and Argentina. By far, the US is the largest producer, followed by Canada and Argentina (EIA 2015; World Energy Resources 2016, 22). Despite difficulties and uncertainties associated with the forecast of recoverable resources from unconventional reservoirs, additional studies have been emphasizing the potential production from unconventional resources in Argentina, mainly in the *Vaca Muerta* region incorporated by Neuquén Basin (Cameron et al. 2018, 293; EIA 2015; World Energy Resources 2016; Mayol 2019; Melgarejo, López, and Montañó Sanz 2013; Bravo 2018).

In that perspective, this thesis aims to reconstruct the process leading to the unconventional reservoirs' successful exploitation. The investigation sheds light on the specific drivers of each country to stimulate the exploitation of these resources. As emphasized by some authors (Anderson 2013; Joskow 2013; Zakaria 2019; Harper 2008), the exploitation of unconventional reservoirs in the US is a long and continuous process of introducing technologies in an economic activity shaping an evolutionary path, instead of a disruptive 'revolution'. Quoting a veteran from the oil business: "If shale gas is a revolution, it is the slowest revolution in history" (quoted by Morrow 2014, 4). Indeed, the quick increase in the US natural gas production observed from 2008 stems from the combination of several factors, some of which have their roots in a relatively distant past. In this case, instead of focusing on the 'revolution' and its further influences, this thesis takes a retrospective viewpoint, observing the direct and indirect determinants leading to the development of frontier zones.

Thesis' methodology

The method chosen to examine the development of frontier zones is the multiple case study. Two main characteristics justify the utilization of this methodology (Tellis 1997, 6; Zainal 2007, 1). First, the development of frontier zones based on unconventional reservoirs is connected with the country context, inhibiting an analysis disassociating the phenomenon of its context. In this case, only a joint study associating the country context and the gradual development of these zones allow us to identify its determinants.

Second, our complex object of study (development of O&G frontier zones based on unconventional reservoirs) have multiple variables, reducing the significance of quantitative analysis. From the perspective that it is impossible to dissociate our object of study from its context (the country circumstances), the multiple variables create a complex environment to establish a quantitative generalization to this phenomenon. Thus, only the case study allows analyzing the issues in-depth since it enables us to examine at the same time process and outcomes through both quantitative and qualitative data relating to multiple variables.

Among all the possibilities of a case study⁴, this thesis adopts the explanatory multiple case study with an additional unity of analysis corresponding to the regional Basins. The

⁴ As explained by Zainal (2007) and Yin (2001), there are three kinds of case studies: exploratory, descriptive, and explanatory. The exploratory case study is recommended to "(...) explore any phenomenon in the data which serves as a point of interest to the researcher." (Zainal 2007, 3). The descriptive case studies is utilized to "(...) describe the natural phenomena which occur within the data in question." (Zainal 2007, 3). Third, the explanatory case studies are shaped to "(...) examine the data closely both at a surface and deep level in order to explain the phenomena in the data. Furthermore, explanatory

explanatory case study allows us to investigate the data and the phenomenon, delimiting relevant patterns from the economic perspective. The embedded unit of analysis corresponds, in the US case, to the Barnett shale region, while in the Argentinean case, it is the *Vaca Muerta* region. In this case, the embedded unit of analysis allows us to investigate relevant patterns and mechanisms scrutinizing the regional dynamics concerning the multifaceted process of overcoming the technological challenge in frontier zones.

In addition to listing and investigating the determinants, according to Bickman (1987), the case study describes the environment in which the phenomenon occurs, describing the context of implementation (Bickman 1987). Thus, the case study allows this thesis to contrast the instrument determining the frontier zones development incorporated in their implementation's context. In this case, this thesis analyzes the complex process relating to the commercial exploitation of frontier zones associating the numerous variables with the particular issues of each country.

Despite the case study methodology's positive aspects, we are attentive to their negative points to improve our analysis's significance. Authors dedicated to exploring this methodology indicates three main negative issues associated with this methodology. First, case studies may be criticized for their lack of rigor. Second, as the study is based on a specific object in a particular context, the generalization is difficult or even impossible. Third, case studies are usually very long, presenting a specific challenge to establish causalities rigorously because of the large amount of data and the multiplicity of elements incorporated (Tellis 1997, 7; Yin 2001, 28–30).

According to Tellis (1997), to avoid the absence of scientific rigor of this methodology, case study must to present three elements: "describing, understanding, and explaining." (Tellis 1997, 3). In this case, this thesis focus on three main steps in each part of our analysis. The first step provides a description associated with data. The second step searches for its causes, revealing the country's context. The third step explains the phenomenon considering our economic perspective. The association among these steps provides the economic explanation for our study object, allowing this thesis to analyze the development of frontier zones based on unconventional reservoirs according to our theoretical framework.

Concerning the second negative point, we adopted multiple case studies to transcend the problems with the generalization, generating an analytical contrast between our object of study

cases are also employed for causal studies where pattern-matching can be used to investigate certain phenomena in very complex and multivariate cases." (Zainal 2007, 3).

(the elements causing the development of frontier zones) associated with each country's contexts. The different countries and their specific context provide a relative diversity, allowing us to qualify instruments and mechanisms structuring the development of frontier zones based on these two cases. Thus, the comparison between these two cases enables the possibility of contrasting these elements, even considering the impossibility of generalizing our results for other countries and regions.

According to Tellis (1997, 8) and Stake (1995) the study length is a positive characteristic since it enables a holistic analysis of the object. However, the authors highlight the necessity to delimit the study boundaries, preventing the lack of scientific rigor associated with the study extension. To demarcate our study's limits, we structure an analytical framework based on frontier zones' features associated with two economic theories: the evolutionary and the historical institutionalist. Thus, our analytical framework fulfills a double purpose: first, it provides the set of variables to analyze in each case; second, it limits the scope of investigation, confining our study extension.

[Our analytical framework](#)

This thesis associates the characteristics of frontier zones with our theoretical support to design the analytical framework. From the frontier zones definition, we assume that some factors mitigate both technological and economic risks. Our theoretical support, based on both evolutionary theory and historical institutionalism, delineates the instruments and mechanisms mitigating frontier zones' risks.

The evolutionary theory offers the theoretical support to analyze the complex process of introducing technological advancements to overcome the challenge presented by frontier zones. This literature affirms that technological change is an endogenous process of the capitalist system, generating qualitative change in society, primarily in the economy. However, this is a complex process, being featured by multifaceted elements connecting agents interested in introducing technological advancements with the market. The evolutionary literature provides the theoretical support to identify factors mitigating the frontier zones' risks. Based on this literature, we identify two elements to investigate: first, focusing forces driving the acceleration of the technological trajectory; second, some mechanisms mitigating the technological risks, encompassing a learning curve and the risk's aversion of companies introducing the technological advancement.

Rosenberg (1976) affirms that prices (in this analysis, natural gas prices) are fundamental to impulse technological development. Nonetheless, the price movements are limited to explain

both sequence and timing of technological advancements. In these circumstances, focusing forces drive the adoption of technological advancements, being additional elements to take into account when analyzing this complex process.

From the evolutionary theory, we highlight two focusing forces influencing the frontier zones development: problems with supply (Rosenberg 1976); and the state role (Dosi and Nelson 2013; Dosi 1982). Thus, this thesis focused on analyzing the country context being attentive to both focusing forces concerning natural gas supply problems (as shortages or other limitations), and the subsequent government reaction.

According to the evolutionary literature, the learning curve is an intricate process involving the accumulation of knowledge, R&D efforts, learning by doing and, the heuristic of research. All these elements provide multiple feedbacks among agents and markets, characterizing the complex process relating to the learning curve. Additionally, companies engage in the complex process introducing technological advancements focusing on achieving higher profits (reducing production costs or increasing productivity) (Dosi 1982; Dosi and Nelson 2016). In this context, the learning curve is the representation of this multifaceted process characterized by multiple feedbacks with an opportunity for companies interested on introducing technological advancements due the possibility of higher further profits.

Nonetheless, we emphasize that the process of introducing technological advancements is featured by multiple *ex-ante* risks concerning the technical feasibility and market acceptance, configuring a high risk for companies interested in engaging in a learning curve process. Under these conditions, the companies' heterogeneity within an economic system is a positive aspect for the technological change, mainly based on their different risk aversion. Companies with lower risk' aversion (or higher appetite for risks) may accept to engage in a learning curve by introducing technological advancements to capture higher profits in the future (Dosi 1982; Dosi and Nelson 2016).

In our economic perspective, institutional dynamics are of first importance to explain the frontier zones' development, demanding an analysis concerning the gradual institutional redesign. Institutions are an open and broad concept, incorporating several social and economic dimensions encompassing formal or informal mechanisms to constraint and direct behavior (North 1991). We preserve the definition of institutions brought by North (1991), focusing on rules and standards constraining the actors' behavior.

In both countries, we are in the presence of a long historical development process associated with an institutional change. The initial objective of implementing instruments is to

increase natural gas supply and not necessarily the development *per se* of frontier zones based on unconventional reservoirs. Consequently, this thesis fits into historical institutionalism approaches as developed by Thelen (2002; 1999) with a relevant role dedicated to examine the context of the instrument's implementation, its origins, its sequence, the strategic actions, and certain choices over others (Thelen 2002; 1999). This emphasizes allow us to analyze the reforms on the regulatory framework through a long term perspective, enabling this thesis to identify the reforms' trajectory.

Taking both perspectives from evolutionary theory and historical institutionalism, we define the thesis's analytical framework encompassing two mechanisms and three instruments. Concerning the mechanisms, we analyze the learning curve, and the company's risk aversion. Concerning the instruments, we examine institutional reorganization focusing on changing the regulatory framework, cooperation between the public and private sectors, and financial support (through the tax system, subsidies, or others).

Main lessons and results:

The analysis of both countries through our analytical framework allowed us to identify similarities and differences in the frontier zones' development process. Therefore, we identify relevant lessons for governments interested in developing their frontier zones based on unconventional shale reservoirs. We share our lessons on two main categories: the necessary conditions guaranteeing the frontier zones' profitability; and elements favoring to adopt technological advancements.

This thesis reached four main lessons relating to the necessary conditions guaranteeing the profitability to achieve the commercial exploitation of unconventional reservoirs.

First, the analysis of both cases, mainly the learning curve, demonstrates the sensibility of unconventional shale reservoirs to natural gas prices. In both cases, the different learning curve stages happen during a movement of natural gas prices increase. In the US case, this is leading by market forces, while in Argentina, it is provided by the government minimum guaranteed price. Thus, we conclude that the necessary engagement of companies in a learning curve to adapt the technologies to the local context demand higher natural gas prices (or even a movement of increasing prices) to mitigate economic risks associated with frontier zones development.

Second, both countries faced problems on normal supply previously of any government effort to improve the profitability for exploration and production (E&P) of natural gas. In the US case, these constraints happened after the first oil shock in the 1970s, while Argentina faced a

supply crisis in 2004. After these problems in supply, both countries mobilize instruments to cope with frontier zones' risks.

Third, both governments adopt financial support for natural gas producers, which differ depending on the particular economic and institutional context. These financial support has as the main objective to improve the profitability for actors accepting the risks associated with the process of introducing technological advancements. The US implements a price differential for high-costs regions related to a tax credit, while Argentina creates a minimum guaranteed natural gas price. We emphasize that, from the investor's perspective, both elements increase the natural gas prices mitigating economic risks of frontier zones.

Fourth, analyzing the institutional change from a long-term perspective based on our historical institutionalism approach, both countries engage in successive institutional reorganizations of the regulatory framework shaping a trajectory corresponding to market liberalization. These reforms focused on leading market forces define natural gas prices, in this case, fitting in a movement to rise natural gas prices. Nonetheless, we highlight that our examination of the country context demonstrates that this trajectory has been more challenging in Argentina than in the US, mainly due to the successive economic crisis and its social side-effects.

This thesis identifies three main lessons relating to the process of adapting technological advancements to the local geological context.

First, there is a cooperation between the public and private sectors in both countries. Our analysis demonstrates that the collaboration between these actors aimed to accelerate technological progress mitigating its risks. In the US case, after discussions with the private sector, the government provides funds to delimitate both the unconventional reservoir's potential and the technological trajectory (in this case relating to the adaptation of both extractive methods hydraulic fracture (HF) and horizontal drilling). Associated with this element, the government creates some organizations to provide funds for R&D focused on adapting technologies to unconventional reservoirs (bridging institutions). In Argentina, the cooperation is based on the national oil company (NOC) sharing development costs with private companies, predominantly international oil companies (IOCs). From the comparison between the cases and the different circumstances, we conclude that the US previous experience simplifies Argentina's technological adaptation, demanding another kind of government effort to deal with the frontier zones' technological risks.

Second, Barnett shale and *Vaca Muerta* regions present remarkable similarities related to their learning curves. Both regions have two learning curve stages with well-delimited phases encompassing the technological adaptation and the market structure. The first learning curve stage corresponds to the adaptation of the HF method in the local geological context. Additionally, in both regions, the first learning curve stage is led by an independent company trying to adapt the HF method to increase productivity and, consequently, reduce production costs.

The second learning curve stage corresponds to the HF association with horizontal drilling. This stage is featured by increasing participation of other players in a movement to catching up with the leader's achievements. Additionally, in this stage, larger companies acquired the independent company leading the first stage. In the US case, a higher independent company merged with the previous leader. In Argentina, the national oil company acquired the two companies with a higher market share in the first learning curve stage. Finally, a remarkable difference is the international oil companies' presence during the two learning curve stages in Argentina, demonstrating the progressive consolidation of areas based on unconventional reservoirs by major companies.

Third, as described in Dosi (1982), the process of introducing a technological advancement is shared in two phases, emergence, and maturity. These phases present particular features corresponding to our learning curve stages. In the first phase, the high risks involved in the technological introduction demand companies with lower risks' aversion, precisely the feature of independent companies. The second phase is featured by increasing competition, corresponding to the second learning curve phase. The increasing participation is featured by a movement to catching-up with the leaders' achievements demonstrated by the number of active operators in the area and the declining leading share. We emphasize that in both cases (US and Argentina), we found Dosi (1982) description relating to the market structure corresponding to the two learning curve stages. The first learning curve stage is leading by independent companies (characterized by its lower risks' aversion). In contrast, the second learning curve is featured by increasing competition and a leading company's falling market share.

Environment costs

The activities connected to the exploitation of unconventional shale reservoirs have claimed attention because of their environmental and social hazards, mainly generating public anxiety about these activities. In this context, EIA (2012) provided some principles to guide

stakeholders as policy-makers, regulators, and the industry operators on reconciling their interests in this question considering the environmental and social hazards connected with the unconventional reservoir exploitation. Despite these elements are not a determinant of the frontier zones development and, consequently, are not included in our scope study, it is relevant for the expansion of the unconventional reservoirs activities, justifying our inclusion of this topic in our general introduction. Additionally, presenting and discussing these environmental costs derived from the anthropogenic activities of exploiting unconventional shale reservoirs also allow us to delimit the industry 'best practices' to be applied and followed by governments and operators.

The Golden Rules proposed by EIA are connected with "(...) the perceived higher risk of environmental damage and adverse" (IEA 2012, 18) from these activities when compared with other anthropogenic ones⁵ and specifically to the oil and natural gas industry, given that "Many of the human and environmental considerations associated with shale gas production are common to all oil and gas development." (GWPC 2009, 43). Furthermore, the perceived higher risk is connected with the misinformation or even the quantity of information available for society, or in other terms, the availability heuristic. In these circumstances, one of the most relevant Golden Rules established by EIA (2012) is a plan of communications focused on establishing a direct link with society, addressing several dimensions related with the calculated risks from the activity and structured on full transparency (IEA 2012, 18).

To achieve full transparency, the government must enforce operators to monitor and control environmental impacts adopting a rigorous measuring of side-effects from the exploitation activity. Additionally, careful determination and approbation of drilling sites could substantially reduce above-ground effects (2012, 17). To delimitate the 'best practices' and mitigate the environmental costs, it is relevant to comprehend the process of drilling and producing from unconventional shale reservoirs (GWPC 2009, 43). In this regard, we will briefly explain the main environmental concerns connected with the exploitation of unconventional

⁵ "The main reason for the potentially larger environmental impact of unconventional gas operations is the nature of the resources themselves: unconventional resources are less concentrated than conventional deposits and do not give themselves up easily. They are difficult to extract because they are trapped in very tight or low permeability rock that impedes their flow. Since the resources are more diffuse and difficult to produce, the scale of the industrial operation required for a given volume of unconventional output is much larger than for conventional production. This means that drilling and production activities can be considerably more invasive, involving a generally larger environmental footprint." (IEA 2012, 18).

shale reservoirs, shared on four main elements. This exposition also possibility to delimit the 'best practices' to deal with these identified environmental costs.

The first and, probable, the most relevant concern is derived from the water use, destination, and contamination, being classified by EIA as "(...) key issues for any unconventional gas development and have generated considerable public concern." (IEA 2012, 30–31). The hydraulic fracture (HF) demands substantial quantities of freshwater, varying between a few thousand and 20 000 cubic meters (cm)⁶. Usually, this freshwater is obtained from the surface as rivers or lakes. However, it also could come from private water sources, groundwater, or even re-used water. This demand for freshwater could enhance a conflict with other water destinations, mainly agriculture (IEA 2012, 32; GWPC 2009, 64–65).

In this regard, a common demand is to improve its efficient utilization and even the recycling of produced water. Once proceeded the HF, most of this water is recovered through the first weeks of production. In this context, the operators have been continuously reducing the freshwater utilization, increasing the recycling of recovered (produced) water obtained from the flow-back of fracturing fluid (IEA 2012, 30–31).

Once accomplished the HF, between 30% to 70% of the freshwater utilized in operation is recovered during the first days or even weeks of production. According to GWPC (2009, 68), all stakeholders involved in the regulatory process are looking for ways to manage this recovered water, mainly to reduce further demand for freshwater. Furthermore, operators have been incentivizing by governments and regulators to "reduce, re-use, and recycle" freshwater resources through the analysis and implementation of both traditional and innovative methods to mitigate the risks associated with freshwater conflicts and final disposition (GWPC 2009, 68).

Among the possibilities, the most usual is the underground injection. However, underground injection of the produced water is not possible in all regions once it demands the existence of depleted wells or some final destination reservoirs, requiring a complete study about the underground conditions to receive this discharged water. Additionally, the transport and the final destination also increase the truck traffic in the region, increasing the impacts on the environment and the footprint of the activity (GWPC 2009, 68).

⁶ However, as emphasized by GWPC, "(...) the volume of water needed may vary substantially between wells." (GWPC 2009, 64). Additionally: "While the water volumes needed to drill and stimulate shale gas wells are large, they generally represent a small percentage of the total water resource use in the shale gas basins. Calculations indicate that water use will range from less than 0.1% to 0.8% by basin." (GWPC 2009, 65). In this regard, the concern is that the utilization of freshwater by HF process is concentrated during the well drilling period, stressing the water consumption only during this period of time.

Thus, another possibility is the treatment of this produced water to re-use them for other activities. This treatment could generate more water availability in the region or for further operations, and it has been the chosen option for areas short of freshwater. Nonetheless, the availability of treatment plants could be inadequate or inexistent in the area, and a point to be analyzed by operators and regulators (GWPC 2009, 68).

Finally, the re-utilization (recycling) of produced water in other HF processes or even by service companies also has been electing as a 'best practice' since it reduces the further requirements of freshwater. In this case, to recycle the produced water, it is necessary an on-site treatment facility associated with a treatment method. In this case, it allows the utilization of the treated water in further HF operations or its destination to other industrial utilization, including for irrigation. Thus, the recycling of produced water also has been classified as a 'best practice' for further developments of unconventional shale reservoirs achieving the industrial scale (GWPC 2009, 68–70).

The second concern is connected with the higher contribution to the atmospheric concentration of greenhouse gases from the production of unconventional shale reservoirs and the deterioration of the local air quality⁷. This risk is strongly connected with how the operations are carried out (IEA 2012, 20). Thus, we share the explanation about this element by into two phases, exploration and production.

Considering the exploration phase, there are additional emissions from diesel-powered engines (or natural gas, in this case, with lower emissions) used for drilling rigs and HF operations; vehicular and traffic with engine exhaust and dust from unpaved roads; and, the well completion process, that may incorporate the process of venting or flaring some natural gas volumes. Venting or flaring is a helpful instrument to recovery the HF fluid (based on water) that carries out also some quantities of hydrocarbons. In this case, the necessary investment to segregate liquids, sediments, petroleum, and natural gas will prevent some operators from wasting this initial production, reducing the flaring or venting of these small quantities of hydrocarbons. Thus, regulations concerning a limit on flaring and venting are capable to reduce these emissions (GWPC 2009, 72–74; IEA 2012, 35).

⁷ "In some circumstances, unconventional gas production can result in higher airborne emissions of methane, a potent greenhouse gas, of volatile organic compounds (VOCs) that contribute to smog formation, and of carbon dioxide (CO₂) (from greater use of energy in the production process, compared with conventional production). Just how much greater these risks may be [when compared with the conventional operations] is uncertain: it depends critically on the way operations are carried out." (2012, 20).

These regulations could determine the installation and utilization of flash tank separators, allowing the performance of a so-called “green completion” or “reduced emissions completion” (IEA 2012, 27). This “green completion” target mainly segregates liquids, sediments, petroleum, and natural gas, avoiding methane leaks during the well completion. As a result, the utilization of these portable types of equipment may recover, on average, 53% of the natural gas that will be flared or vented compared with the business-as-usual (GWPC 2009, 75).

Considering the production phase, emission could initiate in compressors or pumps required to produce or transport the natural gas. Additionally, in this phase, the fugitive natural gas could be a relevant source of emissions, mainly from problems in the cementation process associated with possible leaks in pipeline connections or equipment malfunctions. In these cases, the first recommendation includes the choice of cement for each well, a process also named cementing design⁸. In the IEA (2012) words, this design is fundamental to “ensure the quality of the well-bore and provide a contingency for remedial cementing, if required.” (IEA 2012, 55).

Additionally, the utilization of some technologies also reduces emissions. According with GWPC (2009, 75), the utilization of IR cameras⁹ to identify fugitive hydrocarbon leaks, reducing potential energy losses (GWPC 2009, 72–75).

We emphasize that in the case of fugitive leaks from equipment, producers have strong economic incentives to mitigate them. These kind of emissions represents malfunctions of equipment and a direct loss for producers. In this context, producers have strong incentives to reduce these emissions to the lowest possible to maximize the equipment duration and their delivery of natural gas to the market (GWPC 2009, 72–74; IEA 2012, 35;55).

The third concern is connected with the environmental impacts of the drilling activities in the wildlife or in the cities. In this regard, the adoption of horizontal wells associated with the sharing of the same area by several wells has reduced this impact and substantially reduced the surface area disturbances. Additionally, concentrating the activity in a single site, or pad (that

⁸ IEA (2012) defines the process of cement design as the necessary previous study of “its liquid properties during pumping (to ensure that it gets to the right place) and then for its mechanical strength and flexibility, so that it remains intact. The setting time of the cement is also a critical factor – cement that takes too long to set may have reduced strength; equally, cement that sets before it has been fully pumped into place requires difficult remedial action.” (IEA 2012, 23).

⁹ “These cameras are tuned to the wavelengths that are reflected by hydrocarbon gases, so that those normally-invisible gases actually become visible as “smoke” in the camera image, thus allowing companies to quickly detect and repair leaks.” (GWPC 2009, 75).

has been hosting more than 16 wells), also reduces the utilization of roadways and utility corridors (GWPC 2009, 48; IEA 2012, 22–23).

Despite that the aggregation of wells in a pad substantially reduces the surface impacts, it is not enough to eliminate the increase in traffic volume, dust and noise. It is relevant to emphasize that this environmental impact is “(...) usually limited to the initial 20- to 30-day drilling and completion.” (GWPC 2009, 49). Although these impacts are limited in time, it could severely damage the welfare of the local citizens and the wildlife, demanding an initial planning phase to minimize the long-term effects on society and nature. This initial planning phase could incorporate the construction of pipes (thus, reducing the truck traffic) or even a compensation for local government for the deterioration of roads or neighborhood disturbances at the drilling phase.

Additionally, regulators have been implementing some measures to reduce the community's negative impacts. According to GWPC (2009), among these measurements, we can quote: detailed setbacks from the main constructions of cities as residences, roadways, churches, and schools; adoption of some means to control visual and noise impacts, including the required use of directional lighting¹⁰ and blanket-like additions acting as an acoustic barrier; and different noise limits considering day-time and night-time (GWPC 2009, 51).

The fourth concern is derived from the negative impacts of drilling or HF the wells, mainly the earthquakes¹¹ and the possibility to pollute sources of freshwater. During the drilling or HF the target reservoirs, there is a possibility to connect aquifers with the hydrocarbons producing zone, polluting the freshwater source with hydrocarbons¹². In this case, governments and regulators have been working with operators to delimit the minimal conditions concerning the well constructions, requiring the installation of multiple layers of protective steel casing and cement to safely protect the freshwater aquifers or other relevant zones as deep faults or other geological features that, if communicated with the HF could produce earthquakes. Furthermore,

¹⁰ That “(...) provides illumination of well sites for worker safety, directing the light downward and shielding the surrounding area to prevent illuminating neighboring residences, roads or other buildings” (GWPC 2009, 51).

¹¹ According to IEA (2012): “The registered earthquakes were small, of a magnitude of around two on the Richter scale, meaning they were discernible by humans but did not create any surface damage.” (IEA 2012, 26).

¹² According to IEA (2012), “The risk of leakage of the fracturing fluid used for shale and tight gas production through the rock from the producing zone into aquifers is minimal because the aquifers are located at much shallower depths; but such migration is theoretically possible in certain exceptional circumstances” (IEA 2012, 44).

these protective measures guarantee that the producing zone is completely isolated from other formations, especially that incorporating aquifers (GWPC 2009, 51–52; IEA 2012, 23;44).

Thesis organization

This thesis has four chapters added with this introduction. We structure these three chapters as follows.

The first chapter overviews the O&G's perspectives and defines frontier zones based on their risk differential. Concerning the O&G's perspectives, the current decline rates of O&G fields guarantee that even considering a fast reduction in demand (or a swift energy transition to low carbon fuels), there is a necessity to provide additional supply. Our working definition of frontier zones is based on an economic concept, being featured by high risks, high costs, and technological challenge. In this case, the frontier zone presents high risks because of its low set of knowledge, an element restricting a better delimitation of its geological and technical-economic risks. Additionally, while the distinction conventional-unconventional is based on reservoirs qualities, the term's frontier zones is based on economic features. In these circumstances, our concept of frontier zones encompasses both kinds of reservoirs, conventional and unconventional.

The second chapter details the analytical framework to analyze the US case based on the Barnett shale. From the investigation of instruments and mechanisms delimited by our theoretical support associated with the country's particular environment, we concluded that instead of a shale 'revolution', there is a long and gradual evolution concerning the commercial exploitation of unconventional shale reservoirs. The shortages and oil shocks lead the US government to mobilize instruments to mitigate frontier zones' risks, mainly increasing natural gas prices and accelerating technological development. From this environment, there are successive E&P investments accumulating knowledge and triggering companies with lower risk aversion to engaging in a learning curve to adapt technologies on unconventional shale reservoirs. An independent company (Mitchell Energy) leads the technological adaptation in a high-risk context, achieving a breakthrough in 1999 and characterizing the first learning curve stage. The proliferation of companies interested in catching up with the leader achievements continuously reduces the leading role, disseminating the technological adaptation to other companies and other unconventional regions, shaping the shale 'revolution'.

The third chapter analyzes the Argentinean case based on the *Vaca Muerta* region, allowing a comparison with the US case. Concerning the common points, both countries face natural gas supply problems, leading the national government to mobilize some instruments to

mitigate frontier zones risks. Additionally, technological adaptation is featured by a learning curve presenting two stages with remarkable similarities. The first learning curve stage is led by an independent company (notably less risk averse) in both countries, demonstrating the frontier zone high risk feature. Concerning the differences, we emphasize the environment that is specific for each country. For Argentina, the analysis of the increasing natural gas production from unconventional reservoirs cannot be done without a reference to the severe economic crisis that this country has experienced. The economic crisis shape the adjustments and reforms proposed, molding the environment and, consequently, the instruments implemented. In particular, the processes of liberalization of the gas industry, an essential factor in the US, are slower and marked by swings, being incomplete. Finally, in Argentina, the second learning curve stage is led by the NOC, YPF, which formalizes the cooperation with IOCs to commercially exploit unconventional reservoirs, while in the US case, this leading role is played by independent companies.

The fourth chapter presents the general conclusion. Similarly to the US case, the development of unconventional reservoirs of *Vaca Muerta* has been accelerating due to a government effort aiming to solve natural gas supply problems. Additionally, both governments mobilized instruments to mitigate technological and economic risks characterizing frontier zones based on unconventional shale reservoirs. The main difference between the instruments is connected with the country's specific context. One example is the financial support that differs according with the general objective due the country's particularities. In the US case, to reduce the external energy dependence, the government focuses on accelerating the extractions from national resources presenting high-cost, among them the unconventional reservoirs. In the Argentinean case, to avoid additional expenses with natural gas imports, the government increase the natural gas prices to enhance the national production disregarding the kind of reservoirs or even the extractive costs

Chapter 1. O&G's perspectives and the frontier zones definition

Despite rising concerns about the consumption of high carbon-intense fuels, it is imperative to increase investment in new O&G fields. Indeed, studies dealing with the effects of stringent environmental policies, variations on Gross Domestic Product (GDP) growth and oil prices conclude in the necessary exploitation of new O&G sources to supply further world demand (BP 2018; IEA 2017; 2018a; EIA 2018b; OPEC 2017). Thus, considering increased O&G demand and the current O&G supply, new O&G fields' development is mandatory in any conceivable future scenario. However, which O&G fields, countries or zones will supply the world demand is an open question. One of the possibilities is to meet this demand by producing O&G resources from frontier zones, which present high extractive costs.

From the investor's perspective, the operation of high extractive cost regions can increase the probability of suffering financial losses, consequently rising its risks. There are some zones in the world that, in addition to having high extractive costs, also present technological challenges to unlocking their resources. This thesis defines a zone that presents high extractive costs, high risks, and technological obstacles as a frontier zone. These features create a harsh and challenging environment compared to other O&G zones.

Therefore, this chapter has three main objectives. First, to provide the O&G perspectives, highlighting possible hurdles for governments interested in exploiting frontier zones. Second, to define the frontier zones concept, differentiating it from other O&G regions. Third, present the evolutionary theory that provides the theoretical framework allowing this thesis to analyse the case study of two frontier zones based on unconventional reservoirs. Thus, this chapter is divided into three sections.

The first section deals with the perspectives for O&G markets until 2040. This section discusses the outlooks for O&G supply and demand. While demand could be negatively affected by key determinants, the current declining curve also decreases the supply further. Balancing these negative influences on supply and demand, there is a necessity of additional investment to guarantee market stability.

The second section defines the frontier zone concept from an economic perspective and considers its high risks, high costs, and technological obstacles. From an investor's perspective, the high costs and technological obstacles are reflected in the risks' magnitude, and increase the probability of a financial loss. In this case, the difference between a frontier zone and other O&G zones is the low level of knowledge regarding costs, influencing the risks' magnitude.

Additionally, to prevent any misunderstandings, we differentiate the frontier zone concept from the concepts of conventional and unconventional reservoirs.

The third section is dedicated to conclusions and presents three outcomes. First, analyzing the dynamics between supply and demand, there is a necessity to develop new O&G fields. On the one hand, the examination of elements negatively affecting demand, notably, new stringent environmental policies, the volatility of oil prices, or dismal perspectives for the world's GDP growth, reveals a possible smooth reduction for future demand. On the other hand, the decline rate gradually reduces supply, demonstrating greater influence according to the field's features such as: its age, its size, its properties, and its localization (on-shore or off-shore). Additionally, augmenting the participation of unconventional reservoirs in the global supply would raise the decline rate, given the higher post-peak decline from these reservoirs. Contrasting the net effects between the reduction in supply and demand, even in the worst case scenario of demand reduction, there is a necessity to provide new O&G supply to keep the balance in the O&G market.

Our definition of conventional, unconventional, and frontier zones forms the second conclusion. While the distinction conventional or unconventional is based on a reservoir's qualities, the frontier zones term is based on economic features. Therefore, we conclude that a frontier zone could encompass both types of reservoirs, conventional or unconventional.

Lastly, we conclude that a frontier zone has a low set of knowledge because of its low level of E&P activities. In this context, the frontier zone's features of high costs and technological obstacles discourage additional E&P activities, reducing the available experience and information to enrich the set of knowledge and better delimit geological and technical-economic risks. This insufficient knowledge level increases the risk's magnitude, shaping the frontier zone's features.

1.1 The perspectives for the O&G market dynamics and the necessity to develop further O&G's zones

Oil has been the first source of energy since the 1950s. Its widespread utilization is a result of several features, primarily its energy intensity and its capacity to be stocked. The figure for natural gas is a little bit different. Its employment has been increasing following concerns about high-carbon intensive fuel consumption and its negative effects on both local and global atmosphere. Computing the world's primary energy consumption in 2019, oil represented 33% and natural gas 24%, summing 57% of all energy consumption (BP 2020).

The debate concerning the O&G markets' outlook has been changing from a focus on supply-side to demand side. The best representation of this shift is the displacement of the focus of discussion from oil supply peak to demand peak. In other words, instead of a physical limit for oil supply given by its natural scarcity, it may become an obsolete energy source given the absence of demand. Nonetheless, we highlight that a demand peak represents a 150-year paradigm breakup because oil has been observing a continuous increase in demand (Pinto Jr et al. 2016; Dale and Fattouh 2018; BP 2020, 2020).

The paradigm's breakdown is based on increasing concerns about the accumulation of CO₂ in the atmosphere and its effects demonstrated by climate change. The rising concerns lead to additional policies restricting fossil fuel consumption, notably of the high-carbon intensives coal and oil (Dale and Fattouh 2018). At first glance, this situation produces a gloomy perspective for oil producers, due to the introduction of stringent environmental policies focused on replacing traditional energy sources, which negatively affected their further demand. For this reason, future policies, societal behavior, and the speed of the energy transition have been in the spotlight of all forecasts for the O&G market dynamics¹³.

This section aims to present the outlook for the O&G market dynamics. For this, we present the outlooks of three institutions: Organization of the Petroleum Exporting Countries (OPEC), International Energy Agency (IEA) and the US' Energy Information Administration (EIA), being attentive to the uncertainty in this kind of exercise¹⁴. These studies confirm that, whatever the possible scenario examined, there is a necessity to develop new sources of O&G. To provide more details about this discussion, we divide it into three subsections.

The first subsection examines three outlooks for world O&G demand in light of different scenarios as a mechanism of reflecting its uncertainty. The uncertainty is based on the difficulty of forecasting price trajectories, GDP growth, or new stringent environmental policies. The

¹³ This concern is exemplified by the OPEC (2019) considerations about the theme in its latest outlook: "It is important to stress that OPEC is fully engaged and supportive of the Paris Agreement. As responsible citizens, we believe that there is no Planet B (...) We also believe that **the oil industry must be part of the solution to the climate change challenge**. The science tells us that we need to reduce emissions; it does not tell us that we need choose one energy over another. Thus, we need to continually look to develop, evolve and adopt cleaner energy technologies across the board; ones that enable us to meet expected future energy demand, in a sustainable and ever more efficient manner and where no-one is left behind." (OPEC 2019, 2 emphasis added).

¹⁴ While OPEC represents the forecasts made by the producers, the IEA encompasses the forecasts made by the consumers' group. Finally, the EIA is made by an independent agency in the US. Thus, we consider that this group of forecasts encompasses all the necessary information about possible future scenarios, even the disruptive ones, as EIA's sustainable development scenario demonstrates.

outlooks reveal that new environmental policies have the main potential to influence demand, generating the possibility of peak demand for oil and flat demand for natural gas.

The second subsection analyzes the world O&G supply considering conventional and unconventional reservoirs' participation, and provides two key conclusions. First, there is a significant expansion in the unconventional reservoirs' participation in the global supply, whatever the scenario. Second, this growing participation of unconventional reservoirs is based on the US's output, indicating this country's central role in furthering O&G market dynamics.

The third subsection explains the decline rates' concept and relevance, concluding with an acceleration of this rate in the future that increases its influence on the global O&G supply. The decline rate is a natural characteristic of O&G production fields and causes a continuous reduction in its extraction rates. This element requires additional investments in Exploration and Production of O&G (E&P)¹⁵ to maintain the current world supply. Additionally, examining the perspective generated by a focus on the decline rate, the increasing participation of unconventional reservoirs in the global supply will raise this rate because of these types of reservoirs' higher post-peak decline rate. In light of this element, even in the worst foreseeable scenario, there is a necessity to exploit more O&G fields and regions to meet the further demand for these fuels.

1.1.1 The O&G world demand

In this section, we examine the forecasts of the world O&G demand, describing the influences of environmental policies, GDP growth, and oil prices made by three recognized institutions. We take as sources of information the outlooks provided by the International Energy Agency (IEA), Organization of the Petroleum Exporting Countries (OPEC), and the US' Energy Information Administration (EIA).

We highlight that all these studies are sensible for their assumptions, mainly: the growth of both population and GDP; the intensity and efficiency of the policies adopted (particularly in China and India, the largest consumers); other fuel price movement; and, the sectorial performance of each country. In this context, utilizing these scenarios is a mechanism of coping with this future uncertainty of O&G's outlook.

While OPEC and the IEA take as a limit the year 2040, EIA's report considers the limit the year 2050¹⁶. All reports demonstrate some confluence, revealing two conclusions concerning

¹⁵ Throughout this thesis, we utilized the term E&P to refer to the upstream sector in the O&G business.

¹⁶ IEA made estimations for 2050 only in its sustainable development scenario.

demand perspectives. First, for natural gas, demand for this fuel is continuously increasing until 2040¹⁷. Second, oil demand depends on key factors, being more responsive to further uncertainty. Its level in 2040 demonstrates this uncertainty, showing all possible results (flattening, increasing or decreasing) according to the different scenarios. Notably, the worst-case scenario is demonstrated introducing new environmental policies analyzed by IEA, concluding by a demand peak over the next few years. The following lines explain more deeply the organizations' scenarios, starting with the IEA report.

The IEA analyzes the O&G markets' further dynamics through three scenarios: new policies, current policies, and sustainable development. Examining the scenarios, they are differentiated by two factors: the annual average primary energy consumption and the relative participation of hydrocarbons in energy consumption. In this case, in the current policies scenario, energy consumption increases on average 1.3% per year, with considerable participation of O&G. In the stated policies scenario, energy consumption increases at a slower pace of 1%, being associated with a significant increase in the participation of low-carbon fuels. Finally, in the sustainable development scenario, primary energy consumption is zero, being associated with a replacement of hydrocarbons by low-carbon fuels¹⁸ (IEA 2019, 38–39). All of the scenarios and forecasts are summarized in Table 1, below.

¹⁷ We emphasize that the single scenario presenting a small decrease in natural gas demand is exhibited in the sustainable development scenario of IEA when in 2040, demand for this fuel presents a small decrease. Notwithstanding this small decline of under 2%, the scenario assumes that energy consumption will not increase. We assess this assumption as highly unlikely, demonstrating that a fall in natural gas demand is also unlikely.

¹⁸ In more detail, IEA forecasts that in 2050 low-carbon technologies supply 60% of the whole energy demand (from less than 20% in 2018). Additionally, oil and natural gas participation in the energy mix of 2050 in this scenario achieves 20% and 18%, respectively. Finally, observing demand for oil, the main sector is the petrochemical, followed by the transport sector, since 17% of existing cars and 40% of existing trucks are fueled with oil derivatives (IEA 2019, 92).

Table 1 - IEA's demand outlook

Scenario	Oil (Mbbbl/d)			Natural Gas (Bcm)	
	Accumulated growth/decrease	2040 level	Peak?	Accumulated growth/decrease	2040 level
Current Policies	25%	121	No	49%	5 891
Stated Policies	10%	106.4	Flattening in 2030	37%	5 404
Sustainable Development	-31%	66.9	Next few years	-2%	3 854

Source: IEA (2019, 132; 178).

The current policies scenario analyses the existing policies, assuming that they will be the same for the entire period of analysis (2019-2040); in other words, it is the business-as-usual scenario. This framework tries to capture the energy market dynamics, considering the current policies already in place and their influences on the market (IEA 2019, 38). In this scenario, world oil demand increases continuously, decelerating after 2025 but without a peak, mainly driven by demand from road transport, aviation, and petrochemicals (IEA 2019, 133). On average, demand raises by 1.1 million barrels per day (Mbbbl/d), achieving the level of 121 Mbbbl/d in 2040. This represents an accumulated increase of 25% (IEA 2019, 132) from the current demand level (96.9 Mbbbl/d in 2018). For natural gas, demand constantly increases, reaching 5 891 billion cubic meters (Bcm), representing a total increase of 49% compared with the actual level of 3 937 Bcm (IEA 2019, 178).

The stated policies scenario assumes that countries will adopt the announced intentions in the energy sector to decrease the use of fuels intensive in carbon, leading the world to a less energy-intensive output (IEA 2019, 38). In this circumstance, demand for oil gradually increases, achieving a total value of 106.4 Mbbbl/d close to 2035, maintaining this level until 2040. Compared to the current world demand, this increase represents an accumulated growth of 10% (IEA 2019, 132). In the case of natural gas, world demand escalates continuously, achieving the level of 5 404 Bcm, meaning an expansion of 37% from the actual level (IEA 2019, 178).

Finally, the sustainable development scenario assumes a widespread adoption of new policies focusing on implementing the 2030 agenda for sustainable development, aligned with the Paris Agreement to limit the rising of temperatures to 2° (IEA 2019, 38). In this scenario, EIA affirms that oil demand would continuously decrease, meaning that the demand already achieved its peak. Thus, the demand continuously decreases until it attains the level of 67 Mbbbl/d in 2040, resulting in a total decrease of 31% (IEA 2019, 132–33). For natural gas, there

is a smooth decrease in demand to 3 854 Bcm in 2040, representing an accumulated reduction of 2% from the current level (IEA 2019, 178).

OPEC assumes only one scenario named by reference case in its latest outlook, examining only the oil market. Under some assumptions¹⁹, OPEC forecasts that oil demand increases from the current level of 98.7 Mbb/d in 2018 to 110.6 Mbb/d in 2040, meaning an accumulated increase of 12% (OPEC 2019, 74).

In its International Energy Outlook of 2019, EIA assumes a reference case and analyzes four deviations from this case concerning oil prices and GDP growth. Thus, EIA presents five scenarios: reference case, high oil prices, low oil prices, high GDP growth, and low GDP growth²⁰. Additionally, it is relevant to emphasize that, different from the previous outlooks summarized here, the Agency takes 2050 as a limit²¹; however, to compare it with others' outlooks, we present the 2040 demand level. Table 2, below, summarizes the data and scenarios.

Table 2 - EIA's demand outlook

Scenario	Oil (Mbb/d)			Natural Gas (Bcm)	
	Accumulated growth/decrease	2040 level	Peak?	Accumulated growth/decrease	2040 level
Reference Case	12%	111.8	No	27%	4 780
High oil prices	11%	110.6	No	44%	5 444
Low oil prices	11%	111.4	No	19%	4 476
High GDP growth	22%	122	No	39%	5 247
Low GDP growth	5%	104.5	No	17%	4 429

Source: Based on EIA (2019e, 14;118-120;134-136).

Examining Table 2, there is not a foreseeable decrease or peak in the EIA outlook for both oil and natural gas. Considering oil, its accumulated growth ranges between 5% in the low GDP growth case and 22% for high GDP growth. Considering all the scenarios, oil demand increases

¹⁹ The population increases by 1.6 billion (from 7.6 in 2018 to 9.2 billion in 2040); an average global GDP increase of 3.3% per year; energy policy focuses on improving efficiency instead of replacing fossil fuels; and, an average rise of 1% in primary energy demand until 2040 (OPEC 2019, 4-6;17).

²⁰ The reference case encompasses demographic tendencies, planned changes in infrastructure and an increase in costs as well as an improvement in technologies. Nonetheless, it disregards changes in national boundaries or major disruptive geopolitical events, technological breakthroughs, and changes in current policies. Additionally, the reference case assumes a global GDP growth of 3% per year on average until 2050. Finally, it assumes an oil price at US\$ 100/bbl while the low oil price case assumes US\$ 45/bbl and the high oil price case assumes US\$ 185/bbl. We emphasize that EIA also makes a forecast observing two additional scenarios concerning GDP growth, low and high, assuming an annual average growth of 2.4% and 3.7%, respectively. Nonetheless, these GDP scenarios are analyzed only for the total primary energy consumption, disregarding the particular fuel's consumption (EIA 2019e, 8-9).

²¹ The consumption of both oil and natural gas is higher in 2050 than in 2040 for all scenarios of EIA.

in 2040 from the current level of 99.9 Mbb/d to 122 Mbb/d. For natural gas, its further demand in 2040 ranges between 4 429 Bcm in the low GDP growth case to 5 444 Bcm in the high oil price case. This increase means an accumulated growth from the current level of 3 770 Bcm, ranging between 17% and 44%²².

1.1.2 The O&G world supply

This section aims to describe the world O&G supply, emphasizing the dynamics linked with the participation between conventional and unconventional reservoirs, when possible. We highlight that all outlooks analyzed shared two similar conclusions for O&G dynamics until 2040. First, unconventional reservoirs will increase their participation in the global supply. Second, the US will consolidate its position as a relevant supplier of both oil and natural gas.

In its outlook for the global supply, IEA discriminates between conventional and unconventional sources for both natural gas²³ and oil²⁴. It is important to emphasize that the sum of conventional and unconventional sources does not represent the total world supply, being necessary to add others' output sources that do not encompass the conventional or unconventional delimitation²⁵. We present a synthesis of the data in Table 3, below.

²² The original data for natural gas is presented on trillions of cubic feet, thus to convert to Bcm, we multiplied the data by 28.3168.

²³ In this case, IEA discloses the data considering natural gas source as: low-carbon gases; conventional gas (from existing and new fields); tight gas; shale gas; coalbed methane; and other production. Thus, to provide the total values for conventional and unconventional production, we assume that the parcels of tight gas, shale gas, and coalbed methane represent the output from unconventional reservoirs while the gas output from conventional reservoirs encompasses the values for existing and new fields.

²⁴ The IEA disaggregates supply on: conventional crude oil (existing fields and new fields); tight oil; natural gas liquids; extra-heavy oil and bitumen; and, other production. In this case, conventional production encompasses both existing and new fields while unconventional production encompasses tight oil and extra-heavy oil and bitumen.

²⁵ This is necessary since IEA aggregates some output sources that cannot be encompassed by this delimitation (the case of low-carbon gases) or even could be produced from conventional or unconventional reservoirs (the case of natural gas liquids). Additionally, we strongly believe that the major part of the increase in natural gas liquids production is based on the unconventional production of natural gas in the US, as mentioned by IEA. Nonetheless, this source also encompasses the liquids produced in Saudi Arabia and Russia, preventing us to incorporate this output on the unconventional source. Finally, this source increases from 4.5 Mbb/d in 2018 to 22 Mbb/d, increasing its total participation in the global oil supply from 4.7% in 2018 to 18.7% in 2040 considering the global oil supply of 117.7 Mbb/d estimated in the current policies scenario (IEA 2019, 139).

Table 3 – IEA’s supply outlook

Scenario	Oil (Mbbbl/d)		Natural Gas (Bcm)	
	Accumulated growth/decrease	2040 level	Accumulated growth/decrease	2040 level
Current Policies	23%	117.7	51%	5 943
Conventional	5%	70.6	31%	3 926
Unconventional	116%	21.8	104%	1 907
Stated Policies	8%	103.5	40%	5 495
Conventional	-8%	61.9	23%	3 694
Unconventional	79%	18.1	78%	1 657
Sustainable Development	-32%	65.1	5%	4 123
Conventional	-45%	36.9	-10%	2 689
Unconventional	20%	12.1	20%	1 115

Source: Based on IEA (IEA 2019, 132; 178).

Table 3 shows that IEA forecasts a significant increase in world production from unconventional reservoir sources, whatever the scenario. Considering the oil case, from the current production level, the output from these unconventional reservoirs increases between 116% in the current policies scenario and 20% in the sustainable development scenario. Similarly, for natural gas, the unconventional reservoirs’ output increases between 104% in the current policies scenario and 20% in the sustainable development scenario. This resilient growth in the unconventional reservoirs’ production is based on the US’ production²⁶.

From a producer’s perspective, the most favorable scenario is the current policies, in which demand increases for oil and natural gas. Nonetheless, there is a reduction in demand in the stated policies scenario compared with the current policies scenarios. Importantly, for both oil and natural gas, the higher decrease is supported by conventional sources. For oil, from a previous growth of 5%, conventional production decreases by 8%. In the case of natural gas, conventional production reduces its accumulated growth from 31% to 21%.

Keeping the producer’s perspective, the worst scenario is represented by the sustainable development case. Oil’s supply achieves a total reduction of 32%, while natural gas supply increases only 5%. In both cases, oil and natural gas, while the conventional sources present a decrease, the unconventional presents an increase from the current level.

²⁶ IEA highlights that the unconventional reservoirs’ output has been presenting as the fastest growing in oil’s history, only comparable to the acceleration in the output of Saudi Arabia in the late 1960s. Additionally, from a production leading by small independent companies, oil majors have been increasing its participation in the unconventional exploitation (IEA 2019, 153).

OPEC examines only the case of oil without disaggregating its data. In its outlook, the organization forecasts that unconventional reservoirs provide the lion's share of future increase in production, however, the organization does not disaggregate its estimations. While the current total production level, 99 Mbbbl/d in 2018, rises to 110.8 Mbbbl/d in 2040, unconventional production rises from 10.7 Mbbbl/d in 2018 to 16.5 Mbbbl/d in 2040²⁷. In proportional terms, while the global supply rises 12%, the unconventional source accumulated an increase of 54% (OPEC 2019, 141–45).

EIA shares its estimations for oil in OPEC and non-OPEC countries. From this perspective, despite the higher supply growth is obtained from countries participating in OPEC, these nations' production is based on conventional reservoirs²⁸. Observing the non-OPEC countries, this group, led by Canada, Brazil, Russia, and the US, increases its total oil production by 17%. Of these countries, Canada and the US constitute the majority of the incremental increase in production from unconventional reservoirs²⁹. Despite this observation, EIA does not disaggregate its forecast, avoiding a more precise analysis of the division between conventional and unconventional reservoir production³⁰.

Considering natural gas estimations, IEA affirms that the US keeps its leading participation in the world supply. More precisely, US production increases by nearly 50%, achieving 1 217 Bcm. This leadership is based on unconventional reservoir production, which substantially increases in this period (EIA 2019e, 140).

²⁷ From the whole volume, the lion's share is from the US. OPEC forecasts that unconventional oil in the US will increase production from 10.4 Mbbbl/d in 2018 to 14.5 Mbbbl/d in 2040. In these conditions, unconventional US reservoirs' output will increase the nation's participation in the global oil supply from 10.3% in 2018 to 13% in 2040, with a peak of more than 16% of the global supply in 2025. Additionally, the other countries contributing to the unconventional reservoirs' output are: Canada (0.7 Mbbbl/d in 2040), Russia (0.5 Mbbbl/d), Argentina (0.6 Mbbbl/d), Bahrain (0.1 Mbbbl/d) and China (0.1 Mbbbl/d) (OPEC 2019, 142).

²⁸ More precisely the output from this group accumulated an increase of 27%, reaching a total volume of 68 Mbbbl/d, primarily from countries in the Middle East (OPEC 2019, 124–26).

²⁹ Despite that the outlook observes that the increment in the output from Russia also is based on the beginning of the unconventional reservoirs' exploitation after 2030, this parcel is still lower than the conventional source. In these conditions, the Agency does not provide a forecast for it. Additionally, Brazil increases its production based on the exploitation of conventional offshore reservoirs from the pre-salt area (EIA 2019e, 128).

³⁰ Observing the data for the US, EIA forecasts that its total production increases from 11 Mbbbl/d in 2018 to a peak of 14 Mbbbl/d in 2040, beginning a smooth decline, reaching the level of 11.9 Mbbbl/d in 2050. Canada increases its production by 5.3 Mbbbl/d, mainly driven by oil's sands projects, achieving in 2050 a total production of almost 10 Mbbbl/d (EIA 2019e, 127–28).

Taking as perspective the global supply, Table 4, below, summarizes the IEA forecasts for oil and natural gas supply.

Table 4 – EIA’s supply outlook

Scenario	Oil (Mbbbl/d)		Natural Gas (Bcm)	
	Accumulated growth/decrease	2040 level	Accumulated growth/decrease	2040 level
Reference Case	11%	111.8	26.9%	4 784
High oil prices	10%	110.6		
Low oil prices	11%	111.4		

Source: Based on IEA (2019e)

Table 4 demonstrates that the IEA outlook does not differ significantly among the different scenarios for the oil case. In 2040, oil production ranges between 110.6 Mbbbl/d in the high oil prices and 111.8 in the reference case, meaning a growth between 10% and 11% of the production level in 2018, 100.6 Mbbbl/d.

Despite the differences in the scenarios among the outlooks explored, all of them accord with the growing participation of unconventional reservoir sources in the further supply of O&G. To finish with the analysis of the further O&G market concluding in the necessity to provide more resources, we dedicate the next section to explaining the decline rate and its tendency to increase according with the expansion of O&G exploitation to both unconventional reservoirs and smaller conventional reservoirs.

1.1.3 The decline rate and its negative influence on supply

The decline rate is the natural decrease in O&G production, revealing a physical restriction on the production level. Because of this natural decrease in production, any forecast concerned with further O&G supply has to compute the decline rate's influence. Additionally, this concept is relevant in the next section’s debate about O&G stranded assets. Thus, we define decline rate and discuss its current level and tendency to increase given the greater global production from unconventional reservoirs³¹ and smaller conventional reservoirs.

Before describing the traditional production profile, we first highlight that the production’s flow is determined by four qualities of reservoirs and fluid, synthesized by Darcy’s

³¹ Here we will limit the discussion to the difference between conventional and unconventional production profile. The economic and geological definition of them will be the theme of the section 1.2.

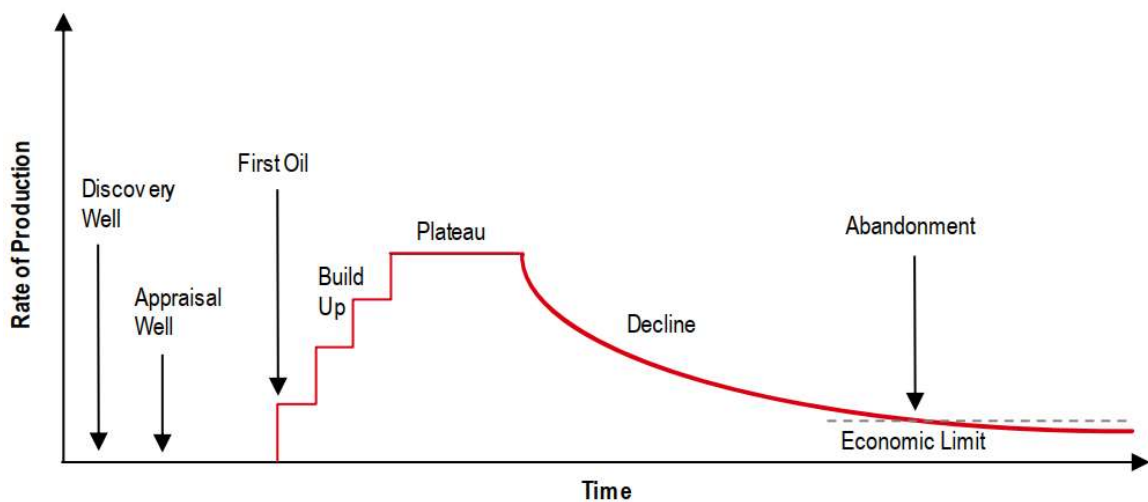
Law. From the reservoir, its permeability, porosity, and pressure are crucial elements. Viscosity is the physical relevant quality for fluid³².

1.1.3.1 The field life cycle and the decline phase

While the natural elements described by Darcy's Law are essential to explaining production flows, standard productive technics on conventional reservoirs also provide a theoretical production profile. The association of the natural reservoir's qualities with productive techniques applied to extract the natural resource provides a theoretical production profile. This theoretical profile has been applied with substantial precision to conventional oil fields (Simmons 2002, 24–27; Robelius 2007; Höök 2009; Cairns 2018, 250). In

Figure 1, the representation of this theoretical production profile allows us to identify three different phases of O&G fields, as well as the three typical phases of an O&G field.

Figure 1 - Idealized oil production profile



Source: Based on Robelius (2007, 32) and Höök (2009, 26).

Synthetically, Figure 1 shows that after discovering a field (discovery well), investors will do an appraisal of the reservoir, looking to ratify its technical and economic viability. After confirming the well's viability, the investor enters the development phase through massive investments. The first oil also demarcates the production build-up and the beginning of a field's

³² The reservoir's porosity is linked to the quantity of pores that the deposit has compared with its total bulk volume. The reservoir's permeability is linked with the rock's quality of allowing liquids to pass through. Larger porosity and permeability ease the flow of O&G, usually termed permoporosity. Additionally, higher pressured reservoirs have more force to expulse fluids when exposed to lower pressure levels. The viscosity of a fluid represents its capacity to flow, thus, lower viscosity reduces fluid mobility, negatively influencing production.

life cycle. Each new production facility adds extra production volume, however, at decreasing rates. In other terms, while the construction of the first facility provides a huge jump in the rate of production, following sites (second, third, etc.) reduce the production increases, revealing a physical limit to increasing the output at the initial rates, and a further peak in production. This decreasing rate of extra production paves the way for the second phase, the plateau.

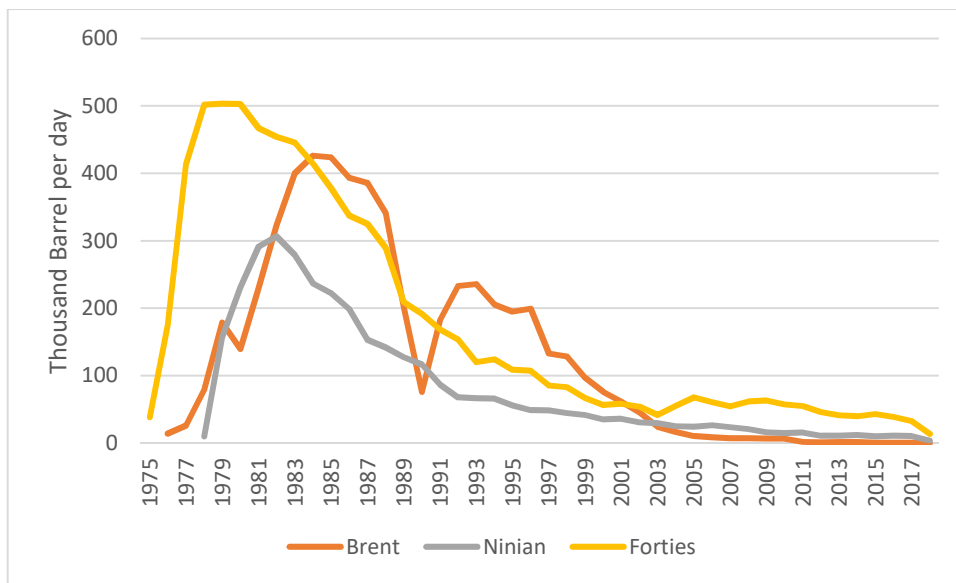
The plateau is a relative stability level in production that could be maintained for several years or even decades, depending on the development plan and the reservoir's characteristics. Usually, the plateau is the phase when investors start applying additional technics to maintain the extraction's flow. These investments aim to delay the production's natural decline that inaugurates the last and longest phase, the decline (Höök 2009; Robelius 2007).

Finally, the decline phase of a field is characterized by a continuous drop in production. In this case, the producer implements several kinds of technics to deal with natural resource depletion, searching for a mechanism to prevent greater production falloff. In other words, producers proceed with technics focused on reducing the field's production pace³³. Another remarkable characteristic of the decline phase is the increase in water production. As the facility has a nominal capacity to extract and treat fluid volumes, the increasing quantity of water in overall production reduces the amount of other fluids that it can handle, notably, oil (Höök 2009; Robelius 2007).

The life cycle of a conventional oil field is well-documented, and an example can demonstrate how the theoretical production profile fits well on real field production profiles. Figure 2 shows the annual production for the three biggest fields on the UK's North Sea, the Forties, the Brent, and the Ninian. These fields were discovered in the UK's off-shore in the 1970s and began production before 1980. As expected, these fields' production profile fits the theoretical profile previously described, providing information about the three phases of the oil field cycle.

³³ Here we are referring to the secondary and tertiary recovery technics. Synthetically, both technics have the same objective: reduce the post-peak decline rate of production or even increase the current production flow. The difference between them is that, while the secondary recovery focused on keeping the deposit's pressure, the tertiary recovery focuses on increasing the fluid viscosity, improving its mobility.

Figure 2 – Annual production from Brent, Ninian, and Forties



Source: Based on OGA (2019).

The production of these three fields in Figure 2 was smoothly by annual averages, being quite similar to the theoretical profile presented in

Figure 1. Notwithstanding, these production profiles mark a life cycle based on the three phases previously described.

Examining the two figures, we can separate the phases starting from the shortest to the longest. The plateau is the shortest phase in a field’s life cycle, depending on several factors to keep its production level. In this case, natural depletion reduces production flows, imposing the necessity of incremental investments to maintain a consistent production level. However, each time the necessary investment to sustain the same production level is higher, increasing the investment demanded to mitigate the resource natural depletion³⁴.

After the plateau, the second shortest phase is the build-up. Massive resources could provide the possibility of proceeding with the extraction through phases, increasing the build-up phase or even the plateau to delay the onset of the decline phase. However, this method also

³⁴ In this case, the plateau is similar to The Red Queen race in the classical book *Through the Looking-Glass* written by Charles Lutwidge Dodgson (covered by the pseudonym of Lewis Carroll). In this book, the Red Queen states: “It takes all the running you can do, to keep in the same place”. In our context, the increasing investment corresponds with speeding up the running to stay at the same place with an identical production level (Likvern 2012).

affects cash flow and investor profits, being assessed in light of the financial requirements and market conditions (Höök 2009; Robelius 2007).

The decline phase, the longest in a field's life cycle, is the most usual phase of a field, providing production to the global supply³⁵. The decline starts after the production's peak, having as a significant characteristic a persistent decline in production levels. Several rates could measure the decrease in production.

1.1.3.2 The decline rate definition

When discussing decline rates, it is essential to distinguish between the post-peak³⁶ and the overall decline rate. On the one hand, the post-peak decline rate refers to individual fields that have already reached its production peak. For these fields, the post-peak decline rate is measured by comparing the current and past production volumes. On the other hand, the overall decline rate reflects the impacts of global supply on all fields. In this case, the overall decline rate is measured by pondering the participation of fields in the declining phase in the global supply, resulting in a percentage that the global supply 'naturally' declines each year. Therefore, the post-peak decline rate is an indicator for individual fields observing its production profile while the overall decline rate considers the association of all post-peak decline rate in the global supply (Sorrell et al. 2009, xiii–xiv; Fustier et al. 2016, 16; IEA 2013, 459). In this thesis, when we mention the decline rate, we refer to this net effect in the world's supply.

In this context, at any time, the global supply encompasses several fields in different phases of the life cycle, i.e., the build-up, plateau, and decline phases. Thus, an increase in the global supply is possible only with the addition of new fields or technics' employment to prevent fields from entering into the decline phase with diminishing production. Consequently, more fields in the decline phase or at a higher decline rate require additional investment to keep the same O&G supply.

³⁵ Despite that the decline phase is also relevant for natural gas, the production profile of this fuel is different from that of oil. The major difference is the stabilization of the production on a long plateau. This long plateau is a direct result of the cost minimization linked with the necessary investments on infrastructure to transport the production. In other words, the construction of pipelines or liquefaction capacity to deal with the natural production peak and the subsequent decline phase are so high that justified artificially constrain the production, creating a long plateau phase instead of a production peak as in oil's case. In this context, the following discussion about the decline rate is more relevant to the oil case instead of the natural gas case.

³⁶ Another term also used in the literature is the depletion rate. Despite that both terms are focused on the declining production, there is a little difference between them. While the depletion rate measures the quantity of resources in place to be recovered (or the remaining recoverable resources), the post-peak decline rates measure the annual rate that the production declined (Sorrell et al. 2009, xiii–xiv).

1.1.3.3 The perspectives for the decline rate linked with three reservoir features: size, location, and quality

Investigating the determinants of the post-peak decline rate for conventional fields, IEA (2008, 221–47) did an extensive study based on 798 fields³⁷, concluding that the most significant feature for determining the decline rate is the reservoir's size. Larger reservoirs are associated with three relevant characteristics: lower post-peak decline rates; lower accumulated production at the peak level as a proportion of the reservoir's size; and lower production at the peak as a proportion of the reservoir's size³⁸. Lastly, we highlight that the field location also is relevant. Off-shore fields are associated with higher post-peak decline rates independently of size and, deep-water fields have even higher rates³⁹ (IEA 2008, 238). Further studies confirm the relevance of larger deposits and their relation with lower post-peak decline rates and, consequently, lower costs of managing the natural decline in production (Fustier et al. 2016; Sorrell et al. 2009; Aleklett et al. 2010; Miller 2011; Höök et al. 2014).

Reservoir size is the most relevant metric for determining the decline rate, and the world's average reservoir size has been shrinking. Several authors have observed that the average size of the fields discovered and the number of single giant fields⁴⁰, have been decreasing. Considering that smaller fields have higher post-peak decline rates, the reduction in the average reservoir's exploitation should increase the decline rates (Simmons 2002, 14; Robelius 2007, 81–82; Höök et al. 2009, 40; IEA 2018b, 85; Sorrell et al. 2009, 24–25; Fustier et al. 2016).

³⁷ From the 798 fields, IEA affirms that obtained the world's 54 super-giant fields, and "the bulk of the giant producing fields (263 out of a total of around 320)" (IEA 2008, 224). Accordingly with IEA, a super-giant is defined as a field having initial reserves of 0.5 billion barrels, and a giant is defined by its reserves in the range of 500 million to 0.5 billion barrels (IEA 2008, 225).

³⁸ Dividing the 580 fields into three categories, super-giant, giant and large fields, IEA affirms that the decline rates were 3.4%, 6.5% and 10.4%, respectively. For the production peak and the accumulated production considering the whole reservoirs, while super-giant fields peaked when they produced 15% of their reserves, giant and large fields produced 17% and 21%, respectively. Considering the current production at the peak as a proportion of the reservoir's size, the figures were 1.7%, 2.3% and 3.9%, respectively for super-giant, giant and large fields (IEA 2008, 230–32).

³⁹ The justification for this is clear: "In part, this is because it is often easier to maintain and upgrade fields on land than those that are found at sea, implying that the [post-peak] decline rate for the former relative to the latter is lower. However, other key factors – such as the need for high flow rates to recover large initial investments – also play an important role in determining actual [post-peak] decline rates." (Aleklett et al. 2010)

⁴⁰ There are two ways to define the giant field, observing its Ultimate Recoverable Resources (URR) or its diary production. The first was created by the American Association of Petroleum Geologists, defining fields with an URR higher than 0.5 billion barrels as giant. The second definition was introduced by Simmons (2002), defining giant fields as those with a diary production superior to 100 000 barrels.

The increasing participation in the global supply of production from unconventional reservoirs negatively affects the decline rate. While the decline rate is a well-studied theme for conventional reservoirs, it is unfortunately not yet well-understood regarding unconventional reservoirs. These reservoirs don't have a production history satisfying a robust prevision on its post-peak decline rate. According to EIA, the actual time series data suggests two main differences between conventional and unconventional reservoirs' production profiles. First, the latter has a shorter life cycle than the former. Second, the build-up and the plateau phases are almost nonexistent for unconventional reservoirs, emphasizing the post-peak decline rate and its strong initial intensity⁴¹ (IEA 2018a; 2018b, 79; 2019, 156). Given the strong post-peak decline rates of production from unconventional reservoirs, the growing participation of these reservoirs in the world supply may enhance overall decline rates. The EIA observes that the increasing investment dedicated to developing unconventional reservoirs has been augmenting its participation in the world supply and, consequently, influencing the decline rate⁴² (IEA 2018a; 2018b, 79).

Understanding the expected standard for conventional production, the differences between conventional and unconventional production profiles, and their influences on the decline rate, we can overview the decline rate forecasts. Several studies suggest that the decline rate ranges between 4% and 9%, translating into a necessity to replace between 4 Mbbbl/d and 9 Mbbbl/d of oil each year. According to Fustier et al. (2016), the drop ranges between 5% and 7%, meaning a production loss between 5 Mbbbl/d and 7 Mbbbl/d. OPEC reckons a decline rate for non-OPEC countries of 5.4% but used 7% as a decline rate for the period 2018-2028, suggesting a smooth increase in this rate and representing an output loss of 7 Mbbbl/d per year (OPEC 2017, 184).

⁴¹ We assume that the current vision of EIA about the production profile of unconventional fields is correct, given discussions from other authors (Holditch 2012, 46; Middleton et al. 2017; Patzek, Male, and Marder 2013; Cornot-Gandolphe 2015, 26; Karra et al. 2015; Lund 2014; Daniel et al. 2017; Dale 2015, 8–10). However, analyzing the data of individual wells, Newell *et al.* (2016, 12–18) affirmed that, on average, the post-peak decline rate for unconventional natural gas production was not different from that of conventional production. Additionally, examining the production profile of unconventional oil fields in the Eagle Ford area, Kleinberg *et al.* (2018, 79) sustained that there are not significant differences between the unconventional post-peak decline curve and the conventional one. While all the attention has been at the well's behavior instead of the field's behavior, we consider that this is a possible open debate that will be solved through the analysis of more data from unconventional production fields.

⁴² The Agency forecasts that unconventional production achieved 9% of the total oil production in 2017 (IEA 2018a). Additionally, the Agency estimates that close to 25% of the total new investment on oil production in 2018 will be designated to unconventional extraction in the US (2018b, 79). Finally, examining only the decline rate for unconventional reservoirs, IEA (2019) declares that unconventional oil reservoirs “tends to decline by between 60% and 70% within 12 months of first production (compared with a decline of around 6% for a conventional well).” (IEA 2019, 153).

Considering oil demand in the sustainable development scenario in 2019, IEA affirms that, without new investment, oil supply would fall 8% per year (8 Mbbbl/d), far more than its forecasted 2% decline in demand per year (2 Mbbbl/d). Additionally, IEA predicts that this decrease in supply could be around 4.5% if there are investments only in existent fields, demonstrating the necessity of investment in new fields to satisfy the world's oil demand. This need holds even in the scenario of a fast energy transition to low carbon fuels, which is associated with a zero increase in the energy demand until 2040⁴³ (IEA 2019, 94–95).

To conclude, the decline rate is an indicator of the current global production structure, demonstrating the necessity of further investment to maintain the global supply. This indicator can be influenced by the production methods and technologies employed to extract resources and the reservoir's qualities. In other words, the resources' price also influences the decline rate, since it generates the necessary stimulus to proceed with technological development or additional recoverable methods. Nonetheless, other elements have been acting to change the global supply structure, influencing the decline rate. Among them, the most relevant are: the reduction in discovery size and quantity, represented by both the aging of giant fields and the increasing relevance of small fields for the global supply; and the rising participation of unconventional reservoirs in the global supply, which have higher post-peak decline rates when compared to those of conventional fields.

Associating the forecasts for the O&G demand with the perspective of acceleration in the decline rate, the necessity for additional investment in the O&G sector is even greater. Even considering the introduction of stringent energy policies focusing on accelerating the energy transition to low carbon fuels, there is a necessity for additional O&G investments associated with the impossibility of stranded assets in the O&G's sector. Although the impossibility of stranded assets considering the current perspectives for O&G supply and demand, there is a risk of O&G resources becoming stranded, a possibility explained in more detail in the box below.

Box 1 - The major risk for O&G resources: becoming a stranded resource

All forecasts of O&G market dynamics have been devoting attention to the effects of the introduction of stringent policies focused on reducing high-carbon fuels' consumption. These policies aim to accelerate the energy transition to low-carbon fuels, creating the possibility of stranded assets in the sector. However, confronting the current decline rate level with the forecasts encompassing stringent energy policies, still there is a necessity to provide additional investments to develop new O&G fields. In this case, considering a stranded asset's definition, the stringent energy policies are unable to create it. However,

⁴³ In the words of IEA: "Continued investment in both new and existing oil fields, even as overall production declines in line with climate goals, is therefore a necessary part of the energy transition envisaged in the Sustainable Development Scenario." (IEA 2019, 95)

broadening our analysis to encompass resources still not developed, there is a possibility of stranded resources, when underground O&G not yet developed will never be extracted.

A stranded asset is an investment that eventually would not meet demand with the necessary price to be fully paid back. Thus, it is different from a worthless investment, and its concept is originated by studies about the effects of regulation on economic activity. Crew and Kleindorfer (1999) studied the energy markets, concluding that new policies could reduce past investments' value, drastically affecting their viability. As explained by Cairns (2018, 249), the stranded asset encompasses all the sunk investments made on a specific asset observing a reduction in its expected profitability, avoiding its previous forecast for capital recoverability and remuneration. In this case, the new regulation or government behavior is unexpected by agents, reducing the previously expected profitability of the project, generating a stranded asset.

Several authors have been claiming that new policies focusing on accelerating the energy transition could generate stranded assets in the O&G sector. To analyze this theme, we first explain the energy transition in the context of the climate change debate and its expected effects in the O&G sector. Following, we summarize the authors and organizations that analyzed this theme, concluding in the remote possibility of stranded assets in the O&G sector.

Scholars denominate as climate change the negative influences that greenhouse gases' overaccumulation causes on the global atmosphere. The increasing quantities of these gases are linked with humankind's actions, notably with the actual energy consumption mix as one of the primary sources responsible for climate change. The widespread utilization of fossil fuels since the industrial revolution has been increasing the quantity of CO₂ on the global atmosphere. Scholars had observed that the emissions overcome the amount that nature can adequately handle and neutralize, starting to over-accumulate CO₂ in the atmosphere. The CO₂ is the primary source of greenhouse gases, and its over-accumulation increases global temperatures with gloomy consequences for the global climate. As the quantity of greenhouse gas emissions has been increasing accordingly with the utilization of fossil fuels, the energy mix has been labeled as responsible for rising temperatures, which trigger changes in the earth's climate. One of the possibilities to mitigate the consequences of climate change is to switch energy sources from high-carbon intensives (coal and oil) to lower ones. This conversion has been labeled as energy transition, and it has the capacity to reduce the quantity of CO₂ launched into the atmosphere, preventing the unfavorable consequences of the climate change⁴⁴ (Stavins 2015; EIA 2017c; Carbon Tracker Initiative 2013; Metz et al. 2005, 78–79; Allen et al. 2009).

An energy transition is one of the possible paths to mitigating the dismal previsions from the over-accumulation of CO₂ in the global atmosphere⁴⁵. The energy transition can take several modes, one of them being disruptive. In this extreme case, worried by the consequences of climate change on human life, governments could choose to phase-out fossil fuels or, at least, the more carbon-intensive coal and oil, through policies forbidding its consumption.

The Carbon Tracker Institute created the term “carbon risk” to emphasize the possibility of stranded assets in several sectors, particularly in the O&G industry, because of the environmental policies focusing on accelerating the energy transition⁴⁶. In such a context, the policy interventions could create stranded investment made to proceed with O&G extraction (Carbon Tracker Initiative 2013). This could mean two

⁴⁴ Among the consequences, Stavins (2015, 22) observes: “(...) changes in rainfall patterns, the disappearance of glaciers, droughts in mid to low-laying areas, decreased productivity of cereal crops, a rise in sea levels, the loss of islands and coastal wetlands, increased flooding, more frequent and intense storms, the risk of species disappearing and the dangerous spread of infectious disease.”

⁴⁵ There are other ways to mitigate climate change, such as: CO₂ capture, use and storage and/or increase in energy efficiency (Metz et al. 2005).

⁴⁶ In this study, the institute advises that investors are exposed to a risk that they were not awarded, the carbon risk. Concerned with the possibility of further stranded assets and consequently, waste relevant capital, the institute analyzed the influences of the carbon risks on capital markets. It concluded that higher societal ecological awareness about the consumption of fossil fuels will influence the adoption of further stringent policies, resulting in a speeding-up of the energy transition, severely affecting capital markets around globe. Finally, examining the evolution of major capital markets such as London and New York, the institute concluded that the exposition of the carbon risk has been increasing over the years (Carbon Tracker Initiative 2013).

different kinds of stranded assets. The first is a total capital loss, with small or insignificant probability. The second is the difference in the revenues obtained in two scenarios, business-as-usual and stringent policies⁴⁷ (Spedding, Mehta, and Robins 2013; D. Nelson et al. 2014; Citi 2015).

Concerned with this question, IEA studied the possibility of stranded assets in the O&G sector due to future stringent policies. The Agency concludes that the adoption of this kind of policy reduces oil demand by 1.5% per year. In light of the actual decline rate, IEA affirms that even a stringent policy would be insufficient to stranded O&G assets (IEA 2017, 153–60). Other authors reach similar conclusions, observing that there are few evidence of stranded assets in the O&G sector's current trajectory. Finally, even with new stringent environmental policies reducing O&G consumption, the decline rates' action demands new investments in new O&G fields (Cairns 2018, 251; Dale and Fattouh 2018; OPEC 2017, 31; Sorrell et al. 2009). Considering the decline curve, IEA forecasts necessary E&P investments close to US\$ 115 billion per year just to maintain the actual production level (IEA 2016, 84). Thus, we conclude that even to manage an estimated oil demand decline of 1.5% per year, additional investments are crucial for replacing the natural production lost because of the decline rate.

Despite the unlikelihood of stranded assets in the O&G sector, even in the presence of stringent policies, there is a possibility of stranded resources. In this case, O&G reservoirs left underground because of several causes, among them, new energy or air quality policies focusing on the energy transition, become a wealth never exploited. Notwithstanding, as Ploeg (2016) emphasized, changes in regulations, law, or societal preferences are just one of the risks faced by O&G undeveloped reservoirs. The author argues that technological evolution could enable superior and cheaper substitutes, a process that is the major threat for the O&G reservoirs and the probable cause of stranded resources. In this case, differently from a stranded asset that reduced its value based on governmental actions shifting market conditions, a stranded resource has its origins in a market mechanism, therefore being encompassed as market risk⁴⁸.

To conclude, while the existence of stranded assets in the O&G market has been suggested, the analysis of the supply's structure, notably the influences of the decline curve, prevents this possibility. However, the feasibility of a stranded resource is real. History has been demonstrating that technological evolution provides alternative fuels to society. In other words, from the time of the utilization of animals, humankind has been evolving in its sources of fuels, each time being conscientious about their side-effects. Thus, the world will phase-out coal, oil, and other non-renewable resources without completely exhausting them, moving the thought from resource scarcity to its abundance/obsolescence. This change will leave some resources underground, discouraging the generation of wealth from this natural resource (Dale and Fattouh 2018; Cairns 2018, 251).

The development of new O&G zones, majorly those presenting high extractive costs and high risks, such as the frontier zones, are the natural candidates for becoming stranded resources. This conclusion emphasizes the relevance to governments concerned with the extraction of O&G resources to transform them into wealth.

⁴⁷ OECD and the UK parliament dedicated time to discussing the theme, obtaining two similar conclusions. First, the stranded assets in the O&G sector will amplify its discussion according with the increased time devoted to debating the energy transition paths. Second, there is a necessity to provide investors with more information, enlarging its visibility and reducing the chances of an abrupt capital reorganization. Thus, increasing the transparency level on this topic may, eventually, reduce both the economic vulnerability to this risk and the adaptation's costs (Baron and Fischer 2015, 22; House of Commons 2014, 36).

⁴⁸ As exemplified by Houser et al. (2017), the collapse in coal in the US is a consequence of the disruptive shale's revolution associated with a dramatic reduction in gas prices. In this case, instead of new stringent policies focusing on environmental or air quality concerns, a technological breakthrough substantially increased the quantity of natural gas, reducing its price. This market movement generates the conditions to substitute coal for natural gas as a source of electricity, representing an energy transition achieved through market mechanisms. This energy transition reduced the CO₂ intensity of the US economy once natural gas is less pollutant than coal.

1.2 Conventional, unconventional, and frontier zone definitions

This section aims to define the concept of frontier zone that may encompass conventional or unconventional reservoirs. While we define frontier zones by three features: high costs, high risks, and technological challenges, our definition of conventional and unconventional reservoirs is based on geological features. In this context, the main difference between frontier zones and other O&G zones is the degree of knowledge about the zone, which influences the risk's magnitude.

Thus, we define a frontier zone by three features:

- i. Costs: there are high costs
- ii. Risks: there are high risks
- iii. Technology: there is a technological challenge demanding an advance in technology or production methods.

These three features characterizing frontier zones could encompass both conventional and unconventional reservoirs. To better define frontier zones and conventional/unconventional reservoirs, we divide the following text into two subsections. The first deals with the conventional and unconventional terminology, setting our definition based on the most typical nowadays, the focus on reservoirs. The second defines a frontier zone, scrutinizing the components structuring its high risks, concluding that the critical difference from other O&G zones is the knowledge level concerning geological and technical-economic risks.

1.2.1 The conventional and unconventional reservoirs definitions

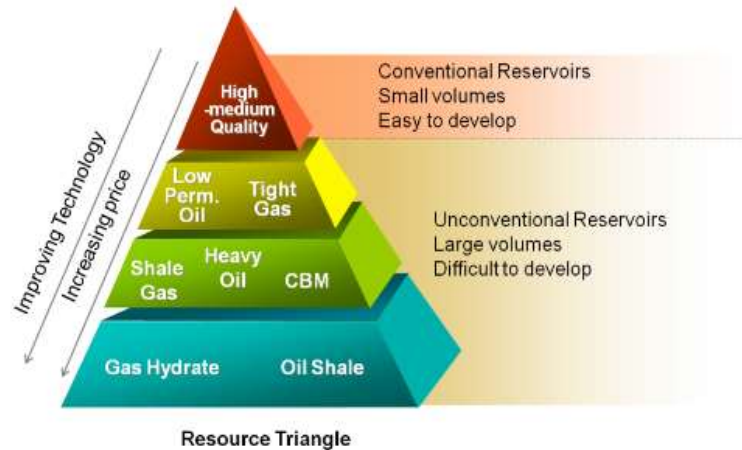
The first author introducing a definition and establishing the borders between conventional and unconventional resources was Masters (1979). The author develops the idea of a resource triangle to categorize O&G deposits according to their quality. Two variables determine the reservoir's quality: the ease of extracting O&G and the resource abundance. The author classifies the easy and scarce reservoirs as conventional, while the most challenging and most vast reservoirs are termed unconventional⁴⁹.

It is straightforward that easy O&G resources are also associated with lower extractive costs. In such a case, the triangular form also illustrates that low cost reservoirs are less abundant than the high cost ones. In light of this affirmation, investors have more incentives to

⁴⁹ It is important to highlight that there is not a standard definition of conventional and unconventional, enabling each scholar to adopt a terminology adequate to his or her focus (McGlade, Speirs, and Sorrell 2013; Ahmed and Meehan 2016, 2–3; EIA 2018a).

access O&G from reservoirs placed on the base's pyramid (presenting higher extractive costs) through technological improvements, price increases, or a combination of both. Figure 3 exemplifies this definition of conventional and unconventional based on the idea of the resource triangle introduced by Masters (1979).

Figure 3– Resource triangle with the border between conventional and unconventional



Source: Reproduction of Dong (2012, 10).

Figure 3 demonstrates that conventional reservoirs are associated with small volumes and are relatively easy to develop. This ease guarantees a low extractive cost and, disregarding issues concerning the political access to this resource, this low extractive cost assures its first exploitation. Advances made by technology and a price increase allow the exploitation of O&G resources from unconventional reservoirs. Unlike conventional sources, they have large volumes, but their extraction is harder, demanding more effort. The low permeability, low porosity, or its geographical localization create natural obstacles outpaced only by strong incentives. In this case, two major factors influence whether these barriers can be overcome, technological evolution and/or increases in prices.

The significant production of unconventional heavy-oil on the Orinoco oil belt in Venezuela and oil's sands in Canada were the focus of interest during the 2000s. In such a context, the term unconventional was refocused to encompass the heavy oil, being frequently described as 'unconventional oil' instead of an unconventional reservoir. This was a redirection of the term to focus on the oil quality instead of the reservoir qualities. In this case, independent of the reservoir quality and size, if oil had low grades, it was classified as 'unconventional oil'. Thus, the terminology 'unconventional' was slightly adapted to describe low oil quality or even

synthetic oil, while other kinds of oils were classified as conventional⁵⁰. In this case, oil's designation as unconventional disregarded the type of reservoir and its qualities, factors that would generally figure into this classification (IEA 2004, 48; Mommer 2004; NEB 2006; Robelius 2007, 100–101; Owen, Inderwildi, and King 2010; Campbell and Laherrère 1998; Hall et al. 2003; Sorrell et al. 2009).

After the US shale 'revolution', the term unconventional returned to focusing on the reservoirs' qualities, more precisely, their permeability and porosity. Since then, the unconventional-conventional border has been defined by the reservoirs' qualities. In these terms, geological elements and traditional exploratory activity searching for a petroleum system are the factors delimiting the boundaries between conventional and unconventional reservoirs. We adopted this terminology to classify a reservoir as conventional or unconventional.

In this respect, a conventional reservoir demands the existence of a petroleum system in a sedimentary basin. In a few words, a petroleum system is a concept that encompasses the association of elements (as source rock, reservoir rock, seal rock, and overburden rock) with essential processes (generation-migration-accumulation and trap formation) to generate an O&G reservoir. Additionally, a conventional reservoir has contact with an aquifer or could be affected by hydrodynamic influences, allowing management focused on preserving reservoir pressure (Magoon and Schmoker 2000, 4; SPE et al. 2017, 16; Ma and Holditch 2015, 73; EIA 2018a).

Inversely, the unconventional reservoir does not demand the existence of a whole petroleum system. In this case, exploratory activity may simply look for a source rock overburden with organic matter, disregarding the presence of the necessary elements to configure a petroleum system. Finally, the unconventional reservoir's last feature is its 'continuous-type' deposit, while conventional deposits are discrete (Jia 2017; McGlade, Speirs, and Sorrell 2013; Babusiaux and Bauquis 2017, 14; SPE et al. 2017, 16; EIA 2018a).

To conclude, this thesis differentiates conventional and unconventional by the associations between the reservoir's qualities and the exploratory activity's focus. Conventional

⁵⁰ For example, NEB (2006, 53–56) defines unconventional as all oils not encompassed by the definition of conventional: "Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.". Hall *et al.* (2003) goes beyond, encompassing also offshore oil as unconventional: "(...) there are unconventional resources such as heavy oil, deep-water oil, oil sands and shale oils that are very energy intensive to exploit." Defining conventional, Sorrell *et al.* (2009, xiii) states: "Taken in this report to include crude oil, condensate and NGLs, and to exclude oil sands, shale oil and extra-heavy oil (non-conventional oils).".

reservoirs depend on two elements: a petroleum system and the natural reservoirs' permeability and porosity. Conversely, the exploratory activity of unconventional reservoirs ignores both elements. Thus, while conventional exploration searches for a whole petroleum system focusing on a reservoir with enough permeability and porosity to reach the O&G extraction rocks associated with a trap, unconventional reservoirs' exploration activity investigates for source rocks and other reservoir qualities. Finally, adopting our denomination of unconventional reservoirs, the most remarkable examples are the US shale, the Canadian oil's sand, the coalbed methane, and the Orinoco oil belt in Venezuela. We dedicate the next section to defining a frontier zone.

1.2.2 The definition of frontier zones by their risks

Despite that the term frontier suggests a geographical delimitation, it actually refers to the association of economic elements regarding the exploratory difficulties of O&G's zones. More specifically, a frontier zone is characterized by three conditions: high costs, high risks, and one or several technological challenges. These conditions create a harsh and challenging environment, positioning this zone close to or beyond what is technically and economically viable. Assuming the resource owner's desire to exploit the O&G zone, the government should move it from technical and economic viability's border. The first step to proceed with this displacement is to unveil the determinants of the high risk. From an investor's perspective, both technological challenges and high costs influence the zone's risks, the first hampering the delimitation of time and costs, and the second being associated with higher vulnerability to financial losses. Thus, this section aims to define a frontier zone by the analysis of its risk structure. For this, we will explain the kinds of risks that E&P activities expose and the elements justifying the view of frontier zones as high risks, in other terms, the determinants of the risks' magnitude on E&P projects.

The standard hypothesis accepted is that economic agents are risk-averse, demonstrating that they prevent financial losses or destruction of value. This aversion means that facing the same profitability, investors will prefer less risk than more. Additionally, investors will calculate the attractiveness of a project by assessing its risks and profits. In other words, when investors face a project presenting a high risk, they will require higher profits to consider it an attractive option (Baunsgaard 2001, 5; Boadway and Keen 2010). Finally, the risk delimitation of investment is essential to investors to assess the project's attractiveness and, subsequently, define its value. We identify two relevant factors in the discussion about risks. The first is the nature of risks and the second is its level, intensity, or magnitude. Thus, there is a difference

between the nature of risk and its magnitude, reflected in its structure. The definitions of the terms risk and risk's magnitude will clarify this point.

We assume that the term risk means a possibility of financial loss or destruction of value, being seen as an undesirable feature of a project. The risk's magnitude encompasses the precision with which investors can assess risk. In this context, we can group risks in different categories, providing the sources of risks in E&P activities as well as in frontier zones. This first inspection will allow us to determine which risks differentiate frontier zones from other O&G zones. After identifying the risks constituting the differences between the zones, we can examine their magnitude.

We share the following discussion in two steps. The first defines the different kinds of risks that an E&P project may face, delimitating which risks differentiate frontier zones from other zones⁵¹. In this case, we share the E&P activities' risks in two categories. The first corresponds to the systematic risk affecting all O&G investors regardless of the region or zone they invest in or produce, i.e., the risks that apply to all the E&P zones. These risks are more general and linked to the O&G market, corresponding to the volatility of prices, liquidity, and market availability. All projects in the E&P are exposed to these risks, justifying our denomination as market risk. The second category encompasses the specific E&P risks differentiating the frontier zones from others, being specifically geological and technical-economic.

The second step assumes an investor's perspective to discuss the risk's magnitude. Taking this perspective, we identify that the determinant of risk magnitude is the investor's capacity to assess risk, depending on the set of knowledge available. A bigger set of knowledge allows investors to delimit both geological and technical-economic risks better, reducing their incapacity to calculate them. We assume that the set of knowledge encompasses two components: information and experience. The public characteristic of these components associated with the low levels of E&P activities on frontier zones reduces the set of knowledge in these zones⁵².

⁵¹ Beyond the frontier zone, Noland and Thurber (2010) identified two other types of zones: mature and proven.

⁵² Another way to present the same relation about risk and its magnitude was presented by Holton (2004). The author considered that risks have two components: exposure and uncertainty. In our analyses, the uncertainty is represented by the set of knowledge, also a measure of the investor's ignorance. The exposure is represented by the decision to invest.

1.2.3 Markets risks

The O&G activities have several attributes that distinguish them from all other economic sectors. Among other elements justifying this complexity, its activities demand coordination among several areas of knowledge associated with considerable technical sophistication. These risks correspond to the volatility of prices, liquidity, and market availability. We will briefly shed light on them.

We define volatility as a measure of the prices' amplitude during a pre-determined time. The prices' volatility affects project profitability, creating a risk. Once we classify O&G as commodities⁵³, we also assume that a producer does not have sufficient power to establish a price. In other terms, the lack of market power to set O&G prices exposed producers to the prices' volatility and, consequently, to this risk (Bindemann 1999, 5; Boadway and Keen 2010; Hansen and Percebois 2010, 137–47).

There is not a consensus about the term liquidity. In this case, the definition of liquidity is the capacity of a good to proceed with large transactions in a short time without considerable loss of value. Thus, it is more appropriate to talk about the level of liquidity among different goods or markets than to define a good as liquid or non-liquid⁵⁴.

Market availability risk is less prominent today and is linked to liquidity risk. Before developing the O&G spot market, there was a risk linked with the possibility of not finding a consumer for the product, i.e., of introducing the product into the market circuit. With the

⁵³ The exact definition of commodity is not an easy task. There is not a universal and precise definition in the literature. Usually commodities are classified as primary products that are internationally traded, being in raw form or with some degree of modification. Additionally, two other characteristics are noteworthy: the trades are based on large volumes; and, there is a strong competition based on price. Although there is some differential because of the quality or even the origin, the base price is given by international markets (Hansen and Percebois 2010, 69–74).

⁵⁴ Accordingly with Hansen and Percebois (2010, 147–51), to classify the markets' level of liquidity we must assess five important elements: the width; the depth; the resilience; the immediacy; and, the exchanged volume. The width refers to the difference between the offering price and the bid price, usually called the bid-offer spread or the bid-ask spread for the designation of that difference. The concept of depth is strictly linked to the concept of width. The depth is the volume traded from a market within a given bid-ask spread, i.e., keeping unchanged the bid-ask spread, the depth answers the question of the quantity of merchandise available for trading. The resilience is defined as the time that a market takes to absorb a price shock disconnected to market fundamentals. The immediacy is the continuation of the concepts of width and depth but adds the factor of volume. In other words, it is the market's ability to absorb large volumes without pronounced impacts in price. Finally, the exchanged volume is the quantity of trades in a market during a period. This definition coincides with the churn ratio which correlates the trading volume with the physical market. The churn ratio represents how many times the same product was traded in the market before reaching its final consumer (Hansen and Percebois 2010, 147–51).

growth of O&G markets, widespread utilization, and the increasing diversification of producers and consumers, this risk has been continuously diminishing.

Another materialization of market availability risk is the necessity of an infrastructure to connect the extraction sites with consumers. In this case, the size of the reservoir plays a critical role in the investment decision. While huge reservoirs offer the necessary future production volumes to build an infrastructure economically, small or medium-sized reservoirs rely on existing infrastructures to make the extraction viable. Finally, we highlight that the necessary infrastructure is more prominent in natural gas activities than oil (Nolan and Thurber 2010, 10).

On this point, we highlight carbon risk as another component of both the liquidity and market availability risks. This risk was named in a study done by the Carbon Tracker (2013), and encompasses two major determinants: the necessity to change the investments of E&P companies from O&G exploitation to other low carbon fuels; and the possibility of a stranded asset, as previously discussed. Both determinants are connected with the energy transition and the possibility of governmental adoption of stringent energy policies to accelerate it. In this case, our definitions of market availability risk and market liquidity encompass carbon risk.

We can group the volatility of prices, liquidity, and market availability generically by the name of market risks. Fundamentally, these risks are shared by all O&G producers. We dedicate the next section to discussing the specific risks, primarily geological and technical-economic, that justify the differences between O&G regions broadly and frontier zones. According to the localization, there are additional risks, notably political risks, however, since these vary by country, we debate them in the box below.

Box 2 – The political risks connected with the breach of contracts and resource nationalism

We are attentive to the political risk in the O&G sector, however, as it varies according to country, it depends on the geographical localization of the reservoir. Nonetheless, we define it and its main elements, the breach of contracts, and resource nationalism.

The literature presents diverse elements encompassing political risk such as: war, civil disturbance, a prolonged fight over power, governmental collapse (summarized as political violence); currency inconvertibility; terrorist attacks; breach of government undertakings; the respect to the institutional framework, and the rule of law (Moran 2004). We divide this huge set of political risks into two groups. The first encompasses elements that governments cannot control directly, being disconnected from the government's aims. The second group includes the aspects connected with the government's actions, being justified by a government objective. While the first group also represents a risk for investors, the second group represents a government objective being frequently centered in the breach of contract.

The breach of contract represents an unfavorable change in terms of the contract/regulations relating to O&G, resulting in a net financial loss to investors and justifying its classification as a risk. This change

may vary from a modification in the tax burden⁵⁵ to outright expropriation of the operation. The breach of contract risk poses a significant threat for investors, being one of the most relevant issues in the debate of the political risks in both economic literature and media.

The literature has been calling any modifications in contracts, including the breach of contract that favored governments over investors, as resource nationalism. Despite the imprecise definition, any reform or negotiation implemented to increase control (directly or indirectly) over an economic activity has been called resource nationalism. Thus, the term has been used to refer to several kinds of contractual modifications⁵⁶. Notwithstanding, the term resource nationalism is an oversimplification of all elements associated with contractual renegotiations (Kahal 2010, 5). In this case, to completely understand resource nationalism, its motivations⁵⁷ as well as its causes⁵⁸, the analyst must “Account for the particular historical, cultural, socio-economic and environmental characteristics of ‘resource nationalist’ countries (...)” (Ward 2009, 18).

History has demonstrated that resource nationalism has a significant motivation to capture more O&G rents (if not all, in the case of nationalization). In such a context, the trigger for modifications in the contractual terms is the upsurges in oil prices and subsequent discussion about the contract terms' fairness. Regressive tax instruments also tend to increase resource nationalism risk since they are not designed to increase the tax burden according to the operation profitability. This possibility opens the discussion about the appropriation of economic rents. Thus, a typical hypothesis links resource nationalisms to price cycles, being this risk larger when the tax systems are based on regressive tax instruments, as in the royalties' case. In other words, the risk of resource nationalism increases accordingly with the oil price, being even higher in the presence of a regressive tax system (Wälde 2008; IEA 2007, 32; Ward 2009, 32–41; Guriev, Kolotilin, and Sonin 2008; Sachs et al. 2012, 350–51; Nakhle 2010, 109).

1.2.4 Geological and technical-economic risks

The first kind of risk that we highlight is related to geological aspects of O&G reservoirs. These encompass the probability of the reservoir's existence, its size, its depth, and its quality (including all the physical factors influencing the reservoir and its recoverability, i.e., its rocks' qualities including porosity, permeability, and pressure). Thus, this risk is a consequence of both the reservoir's natural production and several geological occurrences through the millennia. As natural elements, O&G reservoirs are singular, sharing similarities between them but never identical. To summarize, geological factors affecting risk consist of whether an O&G reservoir

⁵⁵ Notwithstanding, by the vision of Wälde (2008), the terms established by the taxation system are not covered by the contract or by an international law. Thus, in this author view, modifications in the taxation system cannot be considered as a contractual breach.

⁵⁶ Among them, we can quote: increase in the tax burden; repeal of existing contracts; rejection of specific signed terms or contracts; prohibition of IOC to operate in the territory; forced partnerships; increased state participation; increase in the composition of local content; arguments related to energy security (selection of certain deposits for domestic consumption or allocation of O&G production to the domestic market through export restrictions or mandatory sale); or even, imposition of greater social participation or investments in local infrastructure (Ward 2009, 8–9; Sachs et al. 2012, 346; Weiner and Click 2009, 2–3).

⁵⁷ To be implemented they rely on a wide range of arguments that may vary, among them: unpopularity of investors; budgetary needs; and, more frequently, the development of the country. Another plausible argument for these actions might be a power demonstration from governments/rulers; the degree of sovereignty; or the country's independence over other nations (Nakhle 2010, 112).

⁵⁸ Among them, we can mention: changes in the political regime; alteration of party or political leader; environmental protection concerns; alterations in the risk-return relationship; allocation of windfall profits; or, oil prices.

exists, and its natural production flow in time (Bindemann 1999; Boadway and Keen 2010; Daniel et al. 2010, 277; Cairns 1990, 361–62).

The second risk refers to technical-economic viability of the reservoir's extraction, meaning both the technology available to extract O&G from a reservoir and its costs. On the one hand, investors increase the utilization of technologies expecting increasing productivity. On the other hand, higher utilization of technologies increases costs. Consequently, investors have to ponder the expected increase in productivity with the rise in costs. Finally, less investment into technology could mean less productivity, lower extraction rates, or lower levels of Ultimately Recoverable Resources (URR), directly influencing a reservoir's economic feasibility⁵⁹ (Bindemann 1999; Boadway and Keen 2010; Favero, Pesaran, and Sharma 1994, S97).

So far, we have described the O&G sector's risks, starting with the components of market risks. After we defined the components of the E&P risks, geological and technical-economic. Inversely to market risks, geological and technical-economic risks are endogenous to the investor decision. In other words, investors can manage their risks' exposure to both geological and technical-economic factors. The process of managing risks is critical to making decisions about investments and calculating an investment's exposure to risks, as well as to naming risks' mitigation, described in more detail in the box below. The process of managing risks encompasses two elements. First, the identification of the risk exposition and, second, the evaluation of the risk's magnitude. Although risks are inherent to economic activities, O&G activity risks usually reach higher magnitudes compared to other economic sectors⁶⁰ (Bindemann 1999; Boadway and Keen 2010; Pinto Jr et al. 2016; Nolan and Thurber 2010). The risks' magnitude reflects the capacity to assess risks, also measuring the investor's degree of ignorance about the investment. We dedicate the next section to exploring the risk's magnitude.

⁵⁹ Differently from the deposit's size, which presents an invariable unity of O&G encompassed by rocks, URR is an endogenous element, and is determined by human effort. In this context, while geological risk encompasses the quantity of O&G inside rocks, the amount of O&G that can be extracted from a reservoir is an endogenous measurement, varying according to prices, technologies or productive methods used. Additionally, URR also depends on the reservoir location (on-shore or off-shore) and its physical particularities (permeability, porosity and profundity) and other elements.

⁶⁰ The magnitude of the O&G sector's risks is such that vertical integration together with a high level of corporate concentration is seen as a way to share the high risks levels. Thus, vertically integration in the O&G's majors is a way to diversify the risks of E&P activities through various sectors of the industry, seeking a risk/return ratio that compensates for the magnitude of risk exposure (Pinto Jr et al. 2016, 43). Additionally, vertically integrated companies may also have a greater capacity to capture differential rents or achieve economies of scale, creating an additional competitive advantage based on their size (Hansen and Percebois 2010, 73).

Box 3 – Risks' mitigation and the relevance of the E&P phases

E&P activities are risky, and effective risk management is a desirable instrument on which to base an investment decision. Among the factors that provide risk management, the degree of risk exposure is one of the most relevant. The measure of risk exposure depends on two elements: the vulnerability to financial loss and the severity that be achieved. In economic activities, a useful metric for the severity of a loss is the volume invested in a project; as for vulnerability to loss, one can measure the time that an investment is exposed to risks, or its duration (Holton 2003). In this case, while the severity of a financial loss shows the quantity of capital invested considering the risks observed, its vulnerability measures the time that this capital will be exposed to risks. In the O&G context, the degree of risk exposure will depend on the E&P phases.

Assuming that E&P activities may be split into two phases, exploration and development, each phase has different quantities of capital and duration of risk exposure. Observing that all undertakings in E&P are expensive when splitting them into two phases, we can compare the risks considering vulnerability and severity for each stage. In this case, the development phase demands higher capital quantities than the exploration phase, while the exploration phase demands a lower time of risk exposure.

The first element to observe is the different quantity of capital allocated in each phase. In the exploratory phase, investment is dedicated to wildcat wells⁶¹ to investigate the reservoir. Wildcat wells do not demand massive investments. In the development phase, investment is focused on gathering more information about the reservoir's profile through the appraisal activity⁶². Contrary to the exploratory phase, the development stage demands a high quantity of investment to fulfill the reservoir profile with additional information and further build the necessary infrastructure to proceed with the extraction.

The second element is the duration of the investment. In the exploratory phase, the investment outcomes will be exhibited in a few months or years. Conversely, in the development phase, the investment could last for decades. Recently, operations in unconventional reservoirs in the development phase have changed the perspective on time-to-recovery investment, reducing the investment duration. However, considering conventional reservoirs, time in the development phase is still measured in decades.

To conclude, according to the different E&P phases, the degree of exposure to risk changes and the risks' mitigation. In such a context, in the exploration phase, the investment will be exposed to geological and technical-economic risks, however, the capital at risk will be relatively low. Additionally, this investment will not be exposed to risk for a long time. Contrarily, during the development phase, geological risks play a limited part of the total risk, nevertheless, the volume of capital and the time of exposure are higher than in the exploratory phase.

1.2.5 The set of knowledge and the risks' magnitude

The set of knowledge available is the key element for assessing the risks' magnitude in a zone. It captures the degree of investors' ignorance to establish a range of probabilities assessing the E&P risks. In other words, higher information levels provide more elements to set probabilities about crucial factors of geological risks (the reservoir existence, its size, and its quality) associated with technical-economic risks (its method of production, its extractive costs,

⁶¹ Wildcat wells are "drilled to establish (prove) whether petroleum exists in a potential petroleum deposit". Appraisal wells are "drilled to establish the extent and size of a petroleum deposit that has already been discovered by a wildcat well" (NPD 2018).

⁶² The appraisal encompasses drilling other wells to evaluate the reservoir's extension, its potential production and other fluid properties. This process seeks to fill the reservoir profile with additional information, providing new inputs to delimitate further investments to kickoff its commercial production. This set of data will reduce risks about both reservoir quality and volume, providing more detail related to the necessary methods to proceed with its extraction (Nolan and Thurber 2010, 11; Uhler 1976; NPD 2018).

and its productivity). Thus, this section aims to delimit the knowledge components and their influence on the risks' magnitude⁶³.

We define the set of knowledge as the E&P activities that increase the quantity of information available or provide more experience in a zone. In such a case, the set of knowledge is not restricted to successful E&P activities, but also encompasses the unsuccessful ones. Thus, all activity in an O&G zone creates two products: more information about the O&G reservoir's qualities and experience (Nolan and Thurber 2010, 10; Levitt 2016; Cynthia Lin 2013; Hendricks and Porter 1996; Leitwinger and Stiglitz 1984; Hendricks and Kovenock 1989; Porter 1995; Attanasi, Freeman, and Glovier 2007, 10).

Economic literature has described the knowledge features and its effects on economic activities through its cost of generation and the benefits that it generates. Among other characteristics of knowledge generation, we emphasize two: its costs of production and reproduction; and, its positive externalities. The first knowledge feature is that it is expensive to produce but offers low reproduction and access costs. The second feature is that knowledge generates positive externalities, named spillovers. The positive externalities are gains obtained by others that did not participate directly in the effort. The knowledge's spillovers can be defined as perceptible information or know-how that leaks from the knowledge's producer to others that did not pay for its creation. This leak could occur through interpersonal networks, labor mobility, reverse engineering, or even the product's availability on the market (Bureau of Industry Economics 1994, 7; Acha 2002).

The association of these two characteristics creates incentives for governments to establish property rights through laws, protecting the creation of knowledge, and restricting its diffusion. The objective of property rights is to encourage the creation of knowledge, allowing its authors to gather most of the benefits generated by its investment and, at the same time, discourage the action of 'free riders' through the limitation of the spillovers' capture (Acha 2002).

The O&G sector is not different. Usually, governments try to protect knowledge obtained through E&P investment, guaranteeing property of it through law. However, E&P activities give

⁶³ As first explained by the classical study of Knight (1921, 225–33) all risks have a component of uncertainty determined by the absence of enough knowledge. However, in this thesis, we disregard the uncertainty component, assuming that the set of knowledge captures this degree of uncertainty. We opted to utilize the set of knowledge, avoiding the terminology of uncertainty, to lead the discussion's focus on the components of the set of knowledge instead of the differences between risk and uncertainty. For a discussion about risk and uncertainty, see: Lipshitz and Strauss (1997) and Holton (2004).

a clear and public signalization about the results obtained, and it is often possible to capture the most critical information about the venture: the zone's viability and its further perspectives. In this case, an intensification of the appraisal's activities (increasing drilling) or an enhanced production profile signal a discovery, while the complete demobilization of the rig signalizes the failure to find a reservoir commercially exploitable⁶⁴ (Jakobsson et al. 2012; Hendricks and Kovenock 1989; Hendricks and Porter 1996; Levitt 2016; Porter 1995; Reynolds 2001; Cairns 1990, 382). Summarizing, the relevant knowledge in E&P activities, i.e., the discovery of a new production method, a new zone with positive perspectives or viability to proceed with commercial production generates spillovers for other investors as well as governments. More details about the knowledge relevance in the O&G sector and the process of aggregating more information to mitigate risks are provided in two boxes below.

Box 4 - How knowledge influences the discovery rate

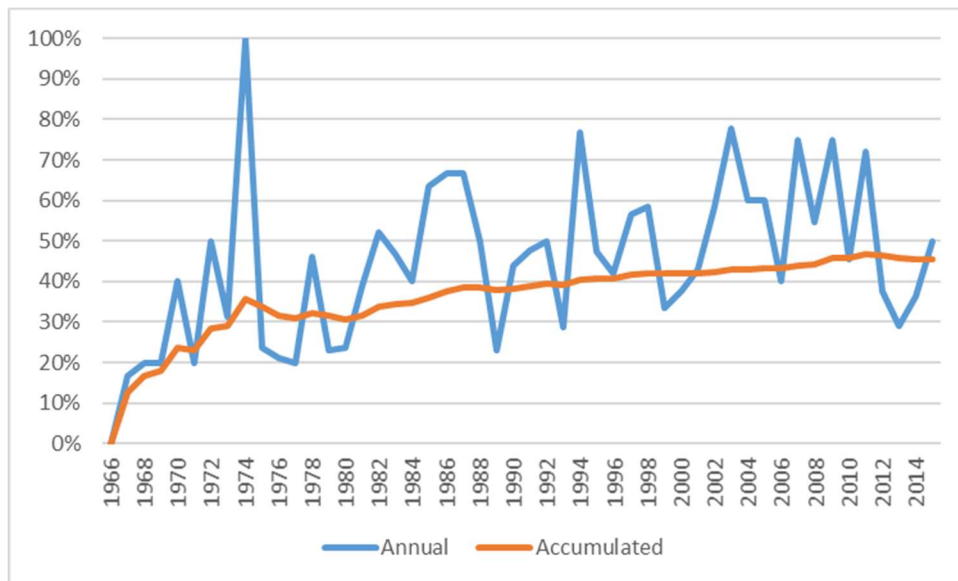
The knowledge acquired by campaigns carried out in the past allows for the superior measurement of probabilities for success and failure in a region, increasing the exploratory efficiency. This information reduces the risks' magnitude, allowing superior risk measurement, and generating positive spillovers. The increase in the discovery rate can summarize all of these elements.

We expect that a commercial discovery in a zone increases the accumulated discovery rate due to the additional knowledge and the reduction of the risks' magnitude. Analyzing data from the Norwegian Petroleum Directorate (NPD) detailing Norway's parcel of the North Sea zone, we observe a continuous increase in the accumulated discovery rate after the first Norwegian discovery in this region. It was necessary to drill eight wells (two in 1966 and six in 1967) to confirm Norway's North Sea zone's first discovery. Figure 4 illustrates how the accumulation of knowledge in this region decreases the risks' magnitude by increasing the discovery success rates⁶⁵.

⁶⁴ This binary possibility creates an opportunity for strategic behavior to delay the exploratory activities while waiting for more information to proceed with the investment, and prevent risk.

⁶⁵ We can define the concept of discovery as it operates in two ways: technical and commercial. While the first is the presence of any vestige of hydrocarbon, the second is its technical and economic viability. We are interested only in the commercial viability, however the Directorate did not specify if the discovery data encompasses technical or commercial viability (NPD 2018).

Figure 4 - Norway's North Sea evolution of wildcat well discoveries - annual and accumulated rates



Source: Based on NPD (2018)

Figure 4 shows a clear continuous tendency of growth in the accumulated discovery rate from wildcat drilling in Norway's parcel of the North Sea. While 1967 marks the point where the commercial activity began here, it also represents the lowest level of the successful discovery rate of this region's history. Then, the accumulated success rate presented an immediate and continuous increase. The most relevant indicator is the steep inclination of this indicator, representing the swiftly increasing way it grows until 1974. Despite the huge variations on the annual indicator, the accumulated success rate for wildcat wells has presented a tendency to increase since the first discovery. The association of these facts demonstrates a clear tendency to increase the likelihood of finding O&G reservoirs during the exploratory drillings.

Box 5 – The decision to drill an exploratory well and the process of gathering more information to reduce the risks' magnitude

The elements influencing the probability of O&G discovery are difficult to evaluate and clarify, being assumed to be a combination of both a theory about the O&G reservoir's existence and a feasible technology that can be used to extract it. In this context, investors are averse to massive investments, rationally assessing the set of knowledge in the zone, looking to mitigate risks through the information examination (Jakobsson et al. 2012; Hendricks and Kovenock 1989; Hendricks and Porter 1996; Levitt 2016; Porter 1995; Menard and Sharman 1975).

Investors mitigate geological risk by getting better estimations of O&G reservoirs before drilling wildcat wells. Usually, investors undertake a geological exploration that focuses on identifying underground rocks, increasing the understanding of a well's formation. This overview utilizes several kinds of equipment to capture seismic data⁶⁶, reducing geological risks associated with the exploratory well. Usually, only after these first investments in information acquisition do investors decide to drill an exploratory well.

Even after reducing geological risk's magnitude through an initial exploration, investors have not still completely delimited technical-economic risk. In other words, despite that geological exploration

⁶⁶ Notably, these methods are the grav/mag and the seismic campaigns. The grav/mag utilizes planes or helicopters carrying sensors to capture anomalies in the earth's gravity and magnetic fields made by O&G. Seismic campaigns are the production of sound waves on the surface and the capture of their reflection by underground rocks, which allows geologists to map the underground.

produces additional information that partially comprises the set of knowledge, it is not enough to precisely delimit geological risk to reduce technical-economic risk's magnitude.

Precisely because of the public nature of O&G data, in this sector, the 'free-riding' problem is intensified. In this case, it is more beneficial for investors to behave as 'fast followers' instead of financing experiments or exploratory activities. In such circumstances, after a discovery, investors strategically follow the pioneer, increasing their benefits without taking part of the previous uncertain investment on experiments or exploratory activity⁶⁷ (Jakobsson et al. 2012; Levitt 2016; Porter 1995; Menard and Sharman 1975; Cairns 1990, 362–63; Acha 2002). The association of these elements justifies governmental action, encouraging or even coordinates the enrichment of the set of knowledge through E&P activities.

A common characteristic of frontier zones is that there are low levels of experience and information about the commercial viability of these types of reservoirs. The reduced size of the set of knowledge about the zone discourages new O&G activities from confirming or denying its viability. Additionally, the public characteristic of the set of knowledge hinders the benefits for investors looking to gather more information about the existence or even the viability of a determined productive method or reservoir. To conclude, the low level of knowledge reduces the capacity of investors to precisely define a reservoir's geological and technical-economic risks. This absence of knowledge is reflected in the risks' magnitude.

1.3 Chapter Conclusion

This chapter presented the concepts of conventional, unconventional, and frontier zones, classifying the first according to its high risk, which is based on the low set of knowledge that accompanies it. Additionally, as our economic concept of frontier zones incorporate the existence of a technological challenge, it is necessary to understand the dynamics concerning the development and introduction of technological progress in the economic system. In this context, this thesis utilizes the evolutionary theory to support this analysis, dedicating a section to explain key concepts of this theoretical framework.

We divided the chapter into two sections. The first handled the O&G perspectives presenting a synthesis of the further market dynamics. This section outlined the outlooks for supply and demand being attentive to the decline rate effects. The second section defined

⁶⁷ Analyzing the Resource and Development sector, some authors have been defending a behavior that is grounded on cooperation instead of competition, naming this as open knowledge. In the open knowledge context, more crucial than the development of an idea is the idea's applicability, or even the creation of a new market (Chesbrough 2003). However, in the O&G sector, specifically in the E&P, our vision is that the traditional model is more adequate than the open knowledge model.

frontier zones through an analysis of their features, centering on their high risk. We established this definition alongside defining conventional and unconventional resources, revealing that an O&G frontier zone could encompass conventional or unconventional reservoirs. Furthermore, we presented the risks in the O&G sector, concluding that the major difference between a frontier zone and another zone is based on the zone's set of knowledge.

From the analysis of O&G supply and demand outlooks, we concluded in the necessity of developing additional O&G fields and zones to supply future demand. Even considering a dismal further perspective for O&G resources, mainly in the case of oil, it is necessary to increase oil supply, given the negative influence of the decline rate. Thus, all the reports analyzed demonstrate the necessity to increase investments in the E&P sector. More precisely, OPEC forecasts an annual investment in E&P of US\$ 368 billion, considering merely oil (OPEC 2019, 146–48). EIA provides two forecasts for the E&P investments of both oil and natural gas. Considering the stated policies scenario, the necessary investment to supply the world demand averages US\$ 689 billion, of which US\$ 90 billion is spent on unconventional reservoirs. In the sustainable development scenario, the necessary investment is lower, given the reduction in oil demand, and reaches an annual average of US\$ 455 billion (IEA 2019, 146). However, the main point here is the necessity of developing new fields, as emphasized by IEA, even in the case of a fast energy transition: “(...) continued investment in both new and existing oil fields is an essential element of energy transitions, even as overall production declines in line with climate goals.” (IEA 2019, 146).

Concerning the O&G frontier zones, we defined it by three features: high costs, high risk, and technological challenges. Accepting this definition, our concept may encompass both conventional and unconventional reservoirs, defined according to their different geological features and other qualities.

Interest in establishing a working definition of the term high risk, we presented the two components of O&G activity risks: market risks, and geological risks and technical-economic risks. While the first kind of risk is common to all O&G projects, the second kind separates frontier zones from others. Examining how risk magnitude is determined, we concluded in the relevance of the set of knowledge, stating that it is the low level of knowledge that distinguishes frontier zones from other O&G zones.

Analyzing the applicability of our frontier zone concept across the globe today, we agreed with Nuttall (2010, 266) and Noland and Thurber (2010, 41–42) that these regions correspond to Arctic, deep-water, and shale operations outside the US. All of these regions have massive

resources, high costs, high risks, and technological challenges, generating a harsh and challenging environment to investors commercially extract O&G. To list the most notable examples of countries that are facing the possibility of a stranded resource in a frontier zone: Canada, Denmark (Greenland), Norway, the US and Russia (in the Arctic case); Angola, Nigeria, Brazil, Mexico and Guyana (in the deep-water case); and, Canada, Mexico, China, Argentina, Brazil, Poland and England (in the shale case).

Chapter 2. Determinants to overcoming the obstacles on frontier zones: the US' Barnett shale case as an example of a frontier zone development

Since 2007, the United States (US) has experienced a sharp increase in its natural gas gross production from unconventional shale reservoirs. Between 2007 and 2018, US natural gas dry production from unconventional shale reservoirs multiplies almost twelve times, from 160 million cubic meters per day (Mcm/d) to 1 710 Mcm/d. Considering the total natural gas dry output in the US, the production from shale increased from 10.7% in 2007 to 72.1% in 2018 (EIA 2020c). An important body of literature has been devoted to this phenomenon. Many factors explaining this development are highlighted: the reserves exhaustion, technological adaptation, the specific institutional environment of the US encompassing the competitive organization of the gas market, favorable taxation, the ownership regime, financial development, weak environmental regulations, and favorable social acceptance (Anderson 2013; Joskow 2013; Burwen and Flegal 2013; GWPC 2009; IEA 2012; Cameron et al. 2018; Morrow 2014; Wang and Krupnick 2013; Middleton et al. 2017; J. Cooper, Stamford, and Azapagic 2016).

It is on the basis of the US experience that the determinants to successfully developing frontier zones based on unconventional reservoirs are identified. The replicability of the US experience reveals the possibilities, constraints, and even the necessary reforms to attain the commercial development of an O&G national frontier zone based on unconventional reservoirs in other countries. Additionally, the US is the only case recognized as a “success story” concerning the development of unconventional shale reservoirs. Therefore, it constitutes the reference case from which we can analyze the experience of all other countries aiming to exploit frontier zones based on unconventional reservoirs.

It is relevant to this thesis to identify these determinants, their relation with a particular country's context, and their implementation processes. This characterization of unconventional reservoirs' development based on frontier zones' particular features allows this thesis to carry out a comparative analysis with the Argentinean case. The identification of the essential variables and its comparison allows the analytical contrast between both cases (US and Argentine), enabling the qualification of the determinants and the contrast between the specific country's circumstances delineating its implementation.

To characterize the development of frontier zones based on US unconventional shale reservoirs experience, we start from the main features of frontier zones, distinguishing them from other O&G zones. Based on frontier zone features, this thesis defines the analytical framework to investigate the determinants of its development.

The first chapter shared the O&G sector's risks in two major categories: market risks encompassing all O&G operations, including those outside frontier zones, and E&P risks. We split E&P risks into two categories, geological and technical-economic risks. While the first encompasses the reservoir's existence, the second is connected to its economic viability. This classification of the frontier zone incorporated features of both conventional and unconventional reservoirs. Nonetheless, our interest is examining frontier zones that are based on unconventional reservoirs, an element demanding another refinement.

In the US shale frontier zone case, the O&G existence was already proven, but the thickness of the reservoirs does not allow a viable production, given the fast decline in extraction rates associated with low recoverability factors. In other words, geological risks are low or inexistent while technical-economic risks are substantial, justifying our emphasis on technical and economic risks that structure the high risks concerning the development of unconventional shale reservoirs. Consequently, in frontier zones based on unconventional reservoirs, geological risks are reduced or even nil.

In this case, we disregard geological risks, focusing on both economic and technological risks. While economic risks are rooted in high production costs, technological risks are based on technological challenges. Concerning technological challenge, it is relevant to emphasize that the decision to accelerate technological adaptation is made under high risks, rooted in the uncertain results from the research; in other terms, *ex-ante* the research results and the market approval, it is impossible to presume its success.

The association of these risks is usually summarized by high production costs which are significantly higher than other production areas. In the US case, unconventional shale reservoirs were frontier zones presenting high-risks marked by exceptionally high economic risks (high production costs) and technological challenges (connected with the necessary adaptation of extraction techniques). The technological challenge for the development of the US unconventional reservoirs has been to accelerate the adaptation of technologies (based on hydraulic fracturing and horizontal drilling), enabling higher productivity and maintaining costs under control.

Consequently, the main challenge for exploiting US unconventional shale reservoirs is to reduce production costs, an element influencing the risks for actors involved in this development process. In these circumstances, the technological adaptation made effective by private actors in the US case has to balance introducing techniques to release natural gas with maintaining its profitability. This balance demands a significant effort from the parties involved in this process to overcome this challenge effectively.

The successful implementation of hydraulic fracture (HF)⁶⁸ and horizontal drilling in the US Barnett shale case is obtained through an intricate network connecting different actors involved in R&D and production, forming a learning curve represented by the progressive increase in the wells' productivity. To provide more detail about the long process concerning the development of unconventional shale reservoirs in the US, this chapter is split into four sections. The first exposes our analytical framework. The second reveals the unconventional shale 'revolution' magnitude. The third explores the determinants of unconventional reservoir's production. The fourth analyzes the gradual development of the Barnett shale based on its learning curve.

2.1 The analytical framework

Several elements have been contributing to a progressive change in the US gas market, influencing the risks, mainly economic and technological, relating to frontier zones. On the one hand, re-organizations in the institutional environment contributed to the reduction of economic risks through gradual reforms focused on both regulatory frameworks and the tax system. On the other hand, the acceleration of research efforts based on the adaptation of HF and horizontal drilling has been reducing the technological risk, generating an opportunity for actors accepting to take risks, with the expectation of achieving higher profits from the successful introduction of those extraction techniques. Analyzing the US experience proves that the state's role is particularly relevant in the initial stages of development, mainly in the definition of the technological trajectory incorporating the adaptation of HF and horizontal wells for the specific reservoirs' conditions, given the highly uncertain results connected with the development of technological progress.

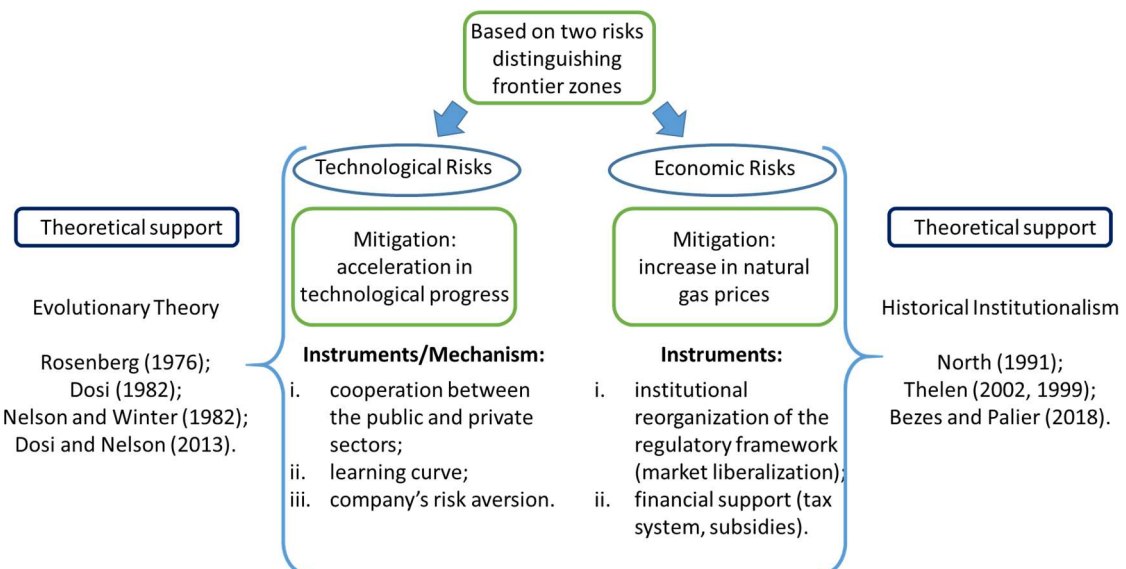
⁶⁸ According with NPC: "Hydraulic fracturing is the treatment applied to reservoir rock to improve the flow of trapped oil or natural gas from its initial location to the well-bore. This process involves creating fractures in the formation and placing sand or proppant in those fractures to hold them open. Fracturing is accomplished by injecting water and fluids designed for the specific site under high pressure in a process that is engineered, controlled, and monitored." (NPC 2011, 34)

The thesis' analytical framework is based on these two risks, economic and technological. While natural gas price increases mitigate economic risks, technological risks demand additional efforts, mainly stimulating and accelerating the necessary technological adaptation with uncertain *ex-ante* results. Additionally, theoretical support provides the instruments and mechanisms utilized to analyze the development process in frontier zones.

The economic risk mitigation is a gradual process consisting of successive reorganizations of the regulatory framework and financial support for high cost zones through the tax system, subsidies, etc. The historical institutionalism approach, based on the contributions of North (1991), Thelen (2002; 1999), and Bezes and Palier (2018), allows this thesis to understand the US natural gas sector's successive reforms as a long process.

The mitigation of technological risks' are scrutinized through the evolutionary theory approach, based on the contributions of Rosenberg (1976), Dosi (1982), Nelson and Winter (1982), and Dosi and Nelson (2013), resulting in one instrument and two mechanisms applied: cooperation between public and private sectors resulting in a prioritization of technological progress; learning curve; and, company's risk aversion. A summary of our analytical framework is detailed in Figure 5, below.

Figure 5 – Thesis analytical framework



Source: Author.

Figure 5 shows that our analytical framework is based on both kinds of risks, technological and economic. A government interested in successfully exploiting its frontier zone based on unconventional reservoirs should distinguish the difference between the risks' structures in order to establish specific instruments to attain commercial production. Concerning the process

structuring the instrument's implementation, the analysis of the US unconventional shale case demonstrates that not all instruments have as the main target to develop frontier zones based on unconventional reservoirs.

Concerning the government's objective in introducing the instrument, we can classify the instruments as direct and indirect. On the one hand, the institutional reorganization of the regulatory framework resulted in a gradual natural gas price increase. Nonetheless, its initial objective was never to enable the exploitation of frontier zones. On the other hand, all other instruments and mechanisms are focused on accelerating the commercial exploitation of unconventional reservoirs. Thus, taking as perspective the government's focus when putting in place the instrument, the institutional reorganization is indirect while the others are direct.

The following section is divided according to the different kinds of risks outlined. This division allows us to provide additional details about the theoretical support and the delimitation of the instruments and mechanisms mitigating frontier zones' risks

2.1.1 The economic risk

Major institutional re-organizations in the US gas market have reduced economic risks associated with frontier zones, two of which are particularly relevant. First, the process of market liberalization is gradual, and encompasses successive reformulations in the regulatory framework. This gradual process enables a significant increase in natural gas prices, and began prior to the shale 'revolution'. These price increases are essential to ensuring the profitability of frontier zones, by influencing the private perspective regarding the necessary accumulation of information and experience relative to the (HF and horizontal drilling) productive techniques. Considering that natural gas prices increased, the market rewards (profits) obtained from introducing technological progress (positively influencing productivity) also increased. Second, financial support is provided through the implementation of a specific tax system designating tax credits for natural gas produced in high-cost regions, such as shale reservoirs. In particular, the tax incentives provide an additional stimulus for producers involved in exploiting reservoirs in frontier zones, generating more E&P investments, and enriching the available knowledge. This element enables the reduction of economic risks associated with operation in these zones.

Both institutional reforms and financial support have progressively improved the profitability conditions for frontier zones, including unconventional shale reservoirs. As emphasized by Rosenberg (1976), profitability is not the primary driver to introducing technological progress; nonetheless, its influence is undeniable in that a higher price is an

additional stimulus for actors involved in introducing new technologies focusing on enabling the economic extraction of O&G from these reservoirs.

Additionally, there are some regulatory reformulations that indirectly influence economic risks. These institutional redesigns also are of first importance in explaining unconventional shale reservoirs' development. Considering these reorganizations, we develop an analysis integrated with neoinstitutional theories such as those initiated by North (1991). In this case, the focus is placed on rules, and standards that constrain the actors' behavior.

Another element to underline is that, from the analysis of the US context, commercial production from unconventional shale reservoirs is the result of factors that have been in place for several decades. If we take gas price increases and tax incentives as an example, these two instruments did not specifically target the development of unconventional shale gas reservoirs. They aimed to respond to a double problem molded firstly by the oil embargos in the 1970s, revealing an undesirable external dependency, and secondly, by the successive natural gas shortages at the end of the 1970s. The association between these problems are relevant drivers for the US government to set up economic incentives proceeding with the institutional reorganizations for the development of new natural gas production areas, including unconventional shale reservoirs' frontier zones.

In light of this element, we are in the presence of a long historical development process whose initial objective was the growth of natural gas supply and not necessarily the development *per se* of unconventional shale reservoirs. Therefore, this thesis fits into historical institutionalism approaches as developed by Thelen (2002; 1999), with a relevant role dedicated to examining the context of the instrument's implementation, the strategic efforts involved, and certain choices made over others.

Adopting this enlarged perspective provided by the historical institutionalists, this thesis could analyze both the US context and the government actions to exploit national energy sources, mainly taking place after the oil shocks. We stress that, after these shocks, the government organized new energy projects in order to attain national energy independence. Despite this broad interest, the government created additional organizations concentrating attention and resources on satisfy the national demand for energy through domestic sources, articulating and shaping its focus on energy independence. The definition of its interest in exploring national resources generates a strategic action shaping additional programs supporting unconventional reservoirs' development. The association of these elements reveals that we are in the presence of a gradual institutional change taking place over a long period with

a relevant role for the US government that articulate an interest in several dimensions, including the exploitation of unconventional shale reservoirs.

Finally, Bezes and Palier (2018) follow the historical institutionalism approach, adding to this theory the concept of the reforms' trajectory. For these authors, when considering the historical institutionalist approach, two elements are essential when analyzing institutional change: the reforms' origins, or the causes of a particular issue, and their sequence. Identifying a reform's origins demonstrates its context, allowing the analyst to identify the interdependencies among different reforms and their components. The analysis of a reform's sequence allows the analyst to observe this phenomenon through a long term perspective and enables the identification of the transformative effect of each reform that shapes and directs the long process of institutional change (Bezes and Palier 2018).

Thus, the reform's origins reveal both its objectives and its nature, while its sequence demonstrates both its interdependence and its transformation effect, forming a connection in the long term between diverse reforms. The association between origins and sequence shapes the process of institutional change with a relevant role for government, shedding light on the directions of institutional change and in its articulation of strategic actions to change the capitalist system (Bezes and Palier 2018). The analysis of these elements in the case study allows this thesis to unveil the trajectory of the natural gas market's reform, which shape the government's strategic actions considering its particular context.

Our analysis of the US natural gas market demonstrates that the institutional reforms focused on solving constraints to the natural gas supply that were centered on the price formation mechanism. While the first issue observed is represented by localized shortages, which affected consumer states supplied by inter-state pipelines that were bound by government price regulation, the oversupply period demonstrates that the problem is connected with government price control. Thus, we conclude in the reforms' sequences shaping a trajectory focused on liberalizing natural gas price formation with a significant government role that motivated actors to attain this target.

2.1.2 The technological risk

The technological adaptation in unconventional shale reservoirs resulted in an exploitation technique associating both HF and horizontal wells, and enabled a significant gain in competitiveness, revealed through the increase in the wells' productivity and reduced production costs. This dynamic process introduce a technological advancement in the economic system generating additional profits for agents involved in this process. Consequently, this thesis

employs the evolutionary theory⁶⁹ to analyze the process concerning the introduction of this technological progress, following the contributions of Dosi (1982), Rosenberg (1976), Nelson and Winter (1982), and Dosi and Nelson (2013). From the evolutionary analysis, the following five elements are particularly highlighted, and shape our analytical framework.

2.1.2.1 Restrictions on normal supply

Issues connected with the normal supply are at the origin of prioritizing the technological progress implemented in unconventional shale reservoirs. Although the technological progress is represented by the adaptation of two techniques previously developed in other context (HF and horizontal wells), it incorporates all the aspects concerning the process of change based on a specific heuristic of research, as previously emphasized by Dosi and Nelson (2013)⁷⁰.

Focusing on the restriction to the normal supply of natural gas in the US experience, represented by the successive shortages in the 1970s, this point coincides with a focusing force⁷¹ stressed in Rosenberg's seminal work (1976)⁷². For this author, some unexpected supply constraint creates a technological bottleneck, leading the actors to face the problem by prioritizing certain technological advancements instead of others (Rosenberg 1976). Examples of these constraints are wars, embargos, or even strikes. An imposition of this kind drives an exploratory search for a satisfactory alternative source or a superior substitute for the product/service or productive process (Rosenberg 1976, 17). An example is the England cotton

⁶⁹ According to Lazaric (2010, 7–30) and Castellacci (2007, 599–600), the evolutionary theory has its deepest origins in Marshall, Veblen, Hayek and Spencer. All authors sought to compare the economic system to biology, highlighting some points in common with the process of biological evolution. In this context, the capitalist economy, based on markets, operates a dynamic co-evolutionary process in which agents seek to thrive through adaptation and evolution considering the environment. This process is based on two characteristics, interaction and co-evolution. Thus, agents seek to differentiate themselves through the introduction of technological advancements resulting in a progressive process that changes the environment, resulting in a dynamic co-evolutionary process. This co-evolutionary dynamic based on the process of change is the object of study of the evolutionary theory.

⁷⁰ Explaining the basic concepts of the evolutionary theory, the scholars affirm that the technological trajectory concept incorporates artefacts and processes of production (that will be the locus of further improvements) and a problem-solving heuristic (delimiting the approach to further improvements). Indeed, while technology defines proximate boundaries of technical feasibility and provides a perspective about further progress, the technological paradigm order and confine possible technological advancements creating an outlook for technological evolution. Additionally, it delimits normative aspects determining the objectives to be improved and the metrics governing the selection among methods, products, services or artefacts (Dosi and Nelson 2013).

⁷¹ The focusing forces channel efforts to a specific technological trajectory, favoring some advances instead of others (Dosi 1982).

⁷² Rosenberg tries to understand the technological change phenomenon through a series of studies compiled in its book of 1976 based on historical experience to shed light on the focusing forces of the technological change (Rosenberg 1976, 1–3).

textile industry in the eighteenth century, when “Kay's flying shuttle led to the need for speeding up spinning operations; the eventual innovations in spinning in turn created the shortage of weaving capacity which finally culminated in Cartwright's introduction of the power loom.” (Rosenberg 1976, 5).

Thus, a restriction on normal supply represents an autonomous stimulus for introducing the pursuit of technological progress to overcome the societal constraint. In this case, this thesis is chiefly concerned with periods of shortages or supply stress in the natural gas market. These periods frequently drive governments to set up plans or reforms focusing on overcoming the issue and its causes, and preventing its reproduction in the future. These strategies modify the incentives for producers, stimulating the adoption of technological advancements that aim to save energy or increase production. Periods of supply constraints are a relevant element directing efforts to the specific technological trajectory relating to HF and horizontal drilling adaptation in unconventional reservoirs.

2.1.2.2 Accumulation of knowledge and a co-evolution leading to a learning curve

The US case demonstrates the relevance of three main elements to attain a successful technological adaptation: first, the accumulation of knowledge (encompassing experience and information); second, the learning by doing, or the additional feedback garnered from the adoption of a trial-and-error approach; and third, the heuristic of research founded on the professional understanding of the technological problem. According to the evolutionary theory approach, the association of these elements shapes a learning curve.

Dosi and Nelson (2013) contend that any effort made to reach a technological advancement is strongly influenced by professional understanding, an element incorporated in the heuristic of research. Additionally, the decision making process in the development of technological progress involves intricate thinking, analysis, discussion, argumentation, testing of models, and compare and contrast. Therefore, the primary basis for technological advancements is the heuristic of research, which is directly influenced by professional understanding. Professional understanding has two main features; first, it is cumulative; and second, it is based on learning by doing (Dosi and Nelson 2013, 4).

The cumulative characteristic of technological advancements is based on gains centered on the heuristics of research which enlarge the scope for professional experiences. In an analysis Lundvall (2016) affirms that the cumulative nature of knowledge stems from social learning, a process in which researchers develop an absorptive capacity by taking advantage of the progress attained by others (Lundvall 2016, 118–32). In Dosi and Nelson (2013) words:

“An important feature distinguishing different paradigms has to do with the cumulateness of innovative successes. Intuitively, the property captures the degrees to which ‘success breeds success’, or, in another fashionable expression, the measure to which innovative advances are made by dwarfs standing on the shoulders of past giants (as such, possibly, the integral of many dwarfs). Cumulateness captures the incremental nature of technological search, and, crucially, varies a lot across different innovative activities.” (Dosi and Nelson 2013, 14).

The learning by doing feature is based on professional experience that gradually improves productive methods, artifacts, products, services, etc., delimiting properties of any production process or artefact and developing improvements. Stimulated by market requirements or obstacles from productive methods, professionals dealing with production revise the techniques used, pushing ahead technological advances. The revision of both techniques and products offers experiences stemming from the actual and more advanced product or productive method design (Dosi and Nelson 2013, 12). A more precise definition of learning by doing is proposed by Thompson (2008) as: “(...) the colloquial name given by economists to the phenomenon of productivity growth associated with, but incidental to, the accumulation of production experience by a firm.” (Thompson 2008, 1).

Additionally, Dosi and Nelson (2013) affirm that, throughout history, no matter how relevant a piece of knowledge is, its existence *ex ante* is insufficient to detail the properties of any artifact or production process. In this case, introducing technologies in the economic system provides scope for improvements, being another locus of actuation for learning by doing. Emphasizing the relevance of learning by doing for technological advancements, Dosi and Nelson (2013) argue that “(...) it is not unusual that technologies are made to work before one understands why they do (...) ” (Dosi and Nelson 2013, 14). This element demonstrates that, occasionally, technological advances are made through experimentation in professional fields, based on learning by doing before any intentional learning through R&D efforts or scientific explication.

The scholars summarize the relevance of learning by doing for the technological progress in three main arguments. First, even assuming a strong comprehension of science by professionals, the main know-how is obtained by field operations rather than scientific training acquired in formal institutions. Second, the professionals’ efforts to overcome the current obstacles exceed the current capacities, resulting in the development of novel technologies. Additionally, the solutions that work or do not work are only wholly understood through field experimentation. Third, the firm’s knowledge (associated with its product details, process, set

of customers and suppliers, and its successes and failures) influences the research activities undertaken. This kind of know-how is rooted in idiosyncratic knowledge, making difficult or impossible to capture through formal institutions teaching science (Dosi and Nelson 2013, 4–5).

While the learning by doing reveals passive learning, the cumulateness associated with the heuristic of the search reveals interactive learning, featuring multiple feedbacks among agents, firm, product, productive process, environment, and market. Consequently, the learning curve concept encompasses additional elements of the evolutionary theory, assuming that both production and accumulation of knowledge form the locus of actuation between firms and markets that, gradually, reduces costs by introducing technological advancements generated by passive and interactive learning. Contrary to passive learning by doing, interactive learning demands that firms be interested in developing and introducing technological progress, in engaging in a learning curve that, in addition to passive learning, allows for research, changes in product design, capital investment, and further activities and enabling an increase in productivity (Thompson 2008).

In this perspective, the learning curve concept incorporates features concerning the introduction of technological progress in the capitalist system relative to a specific technological trajectory in a paradigm as the heuristic of research, the knowledge cumulateness, and the learning by doing. For Lundvall (2016), the learning curve incorporates intentional and interactive learning. While the former represents the accumulation of knowledge through investment in basic research, and is associated with the development the ability to learn from others, the latter incorporates learning by doing (Lundvall 2016). Additionally, Lundvall (2016) affirms that both types of learning, the intentional and the interactive, have multifaceted linkages that influence each other. Finally, the learning curve is influenced by additional elements such as cumulateness, bridge institutions, and even institutional variables.

Moreover, the learning curve demonstrates the appropriation mechanism for firms, integrating the complex process of technological change in the economy. Therefore, this thesis accords with Thompson (2008) and Lundvall (2016) definition of the learning curve as an expression of the multifaceted process between firms and markets that is obtained by introducing technological advancements in the economic system. In these terms, this thesis follows an evolutionary theory perspective, incorporating in the learning curve concept features of cumulateness, learning by doing, and the heuristic of research.

Considering the technological adaptation in the US case based on the development of unconventional reservoirs frontier zone, we conclude in the necessity of successive investments

in E&P, which allow for an accumulation of knowledge. On the one hand, only the company interested in adapting the techniques triggers the accumulation of knowledge based on E&P investments, proportionating both experiences and information. This accumulation of knowledge starts a process of learning by doing, reducing costs according to the production increase. On the other hand, the successful HF technique based on the Slick Water Fracturing (SWF) approach is reached through individual interaction between actors from different companies, demonstrating a process of interactive learning that is based on professional understanding. Finally, we emphasize that the introduction of the SWF approach occurs before the whole comprehension of its effects in unconventional reservoirs takes place, demanding an in-depth investigation to scientifically explain the results from the utilization of the SWF approach for HF unconventional shale reservoirs.

2.1.2.3 The introduction of this technological progress does not represent a technological rupture or a change of paradigm

The development of unconventional shale reservoirs in the US is based on the adaptation of two already existing extractive methods, HF and horizontal drilling, in a completely different geological context. Therefore, these use do not represent a rupture within the delimited technological paradigm. This adaptation is similar to an advancement reached through a specific trajectory considering a technological paradigm, in other terms, it represents a technological progress attained through a pre-determined trajectory.

Technological paradigms provide the scope of techniques and trade-offs to be solved. According to the identification of necessities, consumer requirements, or the delimitation of trade-offs, some technological paths are shaped, generating trajectories concerning this specific paradigm. These forms of progress or even the directions of progress in a determined technological paradigm are termed the technological trajectories. These trajectories focus on improvements of artefacts and productive processes, consist of relatively constant directions and demand both time and effort to be developed. Additionally, technological trajectories are formed by the contributions of different agents involved in the market, promoting gradual technological progress associated with demand satisfaction.

Any advance obtained by a technological trajectory inside a paradigm is considered as technological progress. This advance represents the “natural” progress, as proposed by Nelson and Winter (1982).

Contrary to “natural” technological progress, some advances interrupt the technological paradigm, creating a new one. These advances make a disruptive technology triggering a new

paradigm that is associated with other technological trajectories. Referring to these two possibilities, Dosi (1982) identifies technological progress as continuous and discontinuous. Continuous progress is connected with a change along a technological trajectory encompassed by a pre-determined technological paradigm. In contrast, discontinuous progress is associated with developing a new technological paradigm (Dosi 1982, 147).

Dosi and Nelson (2013) named these two kinds of technological progress 'normal' and 'radical innovations'. Normal technological progress is in line with a given technological trajectory disregarding how fast or to what extent it occurs, while radical innovations are linked with major paradigm changes (Dosi and Nelson 2013, 10).

Technological trajectories channel the progress inside a pre-determined paradigm, revealing a cumulative feature of the continuous progress. It is this cumulative feature that justifies the path-dependence approach in the evolutionary theory.

Conversely, discontinuous progress generates a new technology with new paradigms and their respective technological trajectories. In these circumstances, continuous technological progress is endogenous to the economic system and, once solved, generates additional technological trajectories.

In the unconventional reservoirs frontier zone case, the technological trajectory corresponds to HF and horizontal drilling adaptations in response to challenging geology. In this respect, according to the evolutionary theory definitions, it does not represent a change in the technological paradigm. More precisely, the paradigm in this case concerns the identification of natural gas resources trapped in unconventional reservoirs, which is achieved through a delimited set of techniques used to extract these resources. The trade-off is represented by applying these techniques to attain the highest possible production considering the technological costs. In other words, maintaining the use of the HF method, the actors have to reduce their operative costs and increase the well's productivity, demonstrating the possible trajectory when incorporating technological advancements obtained from the identified trade-off.

2.1.2.4 Introducing technological advancement respecting two industry phases

According to Dosi (1982), technological advances in an economic system generate specific dynamics following two main steps. Concerning this dynamic, the analysis of the introduction of HF and horizontal drilling in the US unconventional shale reservoirs reveals an interesting parallel with the evolutionary theory. While in the first phase (emergence), an actor should

accept taking risks for introducing the technological advancement, the second phase (maturity) is featured by oligopolistic competition. From the examination of the Barnett shale case's learning curve, we observe the delimitation of these two distinct phases, the first incorporating a leading company and the second characterized by growing competition among independent natural gas companies.

Dosi (1982) distinguishes two phases of the introduction of technological change in economies. The first corresponds to the trial-and-error phase, which is characterized by high risks. The second corresponds to the maturity of the technological advancement. According to the author, these two technological phases "(...) correspond historically to two different sets of features of an industry, related to its emergence and its maturity." (Dosi 1982, 157).

In the first phase (the emergence), characterized by the trial-and-error stage, Dosi (1982) emphasizes the relevance of two features of both economic and institutional environments: first, institutions producing basic knowledge to trigger the accumulation of information, experience, failures, etc. Associated with these primary research institutions, is the stimulus from bridging institutions to connect research with market practices (producing the know-how). Second, given the high risk of this initial phase of technological advancements, a diversity of risk-taking agents is required for introducing any differentiation in products, services, or productive processes, presenting a commercial advantage. Even considering that these technologies were originally created in institutions or in established firms, the risk-taking agents are relevant for introducing technological progress in markets (Dosi 1982, 157).

The second phase corresponds with a market maturity when larger firms dominate the production, commercially exploring the diffusion of technological advancements. This phase resembles an oligopolistic maturity when technological advancements become an element of competition among these firms (Dosi 1982, 157–58).

The analysis of the learning curve in the Barnett shale case allows us to identify two stages. The first phase focuses on two objectives: reducing costs and achieving experience and information given the extreme diversity of shale formations. The development strategy is primarily based on a trial-and-error approach that adapts HF to shale reservoirs, resulting in the Slick Water Fracturing (SWF) approach. The process of fracturing reservoirs is not a new technology, however, its adaptation to unconventional reservoirs changes its primary objective. While the fracturing in conventional reservoirs focuses on keeping the reservoir's aperture, in unconventional reservoirs, the main aim is to maximize the connections among natural

fractures. The SWF approach is the most adaptable to reach this purpose. The essential feature in this stage is the presence of a leading company (Mitchell Energy).

Conversely, the second phase is marked by a multitude of producers. The objective is to increase the recoverability factor, increasing productivity based on introducing horizontal drilling from new wells. Although both stages expand the regional knowledge available due to the accumulation of investments in E&P, the positive spillovers are perceptible during the second stage through the increased production of other companies. Additionally, the positive spillovers are embodied by the widespread technological mastery of other shale regions, an element shaping the shale 'revolution'.

2.1.2.5 The risk aversion of actors involved in different phases relating to the introduction of the technological progress

As emphasized by Dosi (1982), the initial stages relative to the introduction of technological progress (the emergence phase) are characterized by high risk due to the uncertain results of the technological advancement. Additionally, this phase demands the existence of risk-taking firms focused on appropriating the economic gains. Thus, the kind of companies involved in developing a frontier zone, and particularly their risks aversion, is relevant for triggering the process of learning (represented by the learning curve) associated with the introduction of technological progress.

The evolutionary theory is centered on heterogeneous agents and firms in a complex and uncertain environment that select successful technologies through markets. In this case, this uncertainty is provided by two main elements. First, there are no guarantees, *ex-ante*, that the engagement in a specific technological trajectory represented by a research project will provide the expected positive results. In other terms, the research project's results are uncertain. Second, even if a firm reach a positive outcome from the research, markets provide approval *ex-post* of the research efforts. In this case, after successfully overcoming the research phase, the new artefacts or productive processes will be selected by market forces (Dosi and Nelson 2013; Dosi 1982).

In these circumstances, both uncertainty and heterogeneous agents structure the dynamics relating to the process of introducing technological progress in the economic system. On the one hand, markets select the successful firms from diverse options, performing an *ex-post* selection mechanism, an element basing the uncertainty for the research efforts. On the other hand, this uncertain economy with an *ex-post* criteria of selection, the existence of agents with heterogeneous risks aversion is fundamental to start the technological change. These

agents, through trial-and-error procedures associated with the search for technological progress, accept to take risks because the markets could provide a substantial profit in the case of success (Dosi 1982, 156).

Concentrating on the Barnett shale case, this thesis identifies a specific actor that accept the risks concerning the adaptation and introduction of HF in unconventional shale reservoirs frontier zone context: Mitchell Energy. This company is characterized as an independent natural gas producer in the US context. Independent companies are usually described as firms accepting high exploratory risk associated with O&G discoveries.

Finally, the Barnett shale case analysis also depends on the agents' historical experiences, as previously emphasized by Dosi (1982). The author contends that one of the forces influencing the technological advancement is based on a company's technological history associated with its expertise (Dosi 1982, 155). Despite that Mitchell Energy's expertise is the E&P activity concerning the extraction of natural gas in the Barnett region, the firm's consecutive failures to utilize horizontal wells in this region discourage this company from pushing forward the research efforts relating to this technological adaptation and, consequently, improving the well's productivity. In this context, it is only after its merger with Devon Energy, a company specializing in horizontal drilling, that the research efforts to associate both extractive methods, HF and horizontal drilling, on unconventional shale reservoirs are resumed.

The state role sharing the technological development risks and coordinating efforts

Rosenberg (1976) emphasizes that cost reduction, a persistent feature in the capitalist economy, could be associated with a price signalization, and shapes the relevant pressure to provide technological advancement. However, only this element (the persistent pressure to reduce costs and increase price) is insufficient to completely explain the technological change's drivers. Moreover, price signalization is also incapable of explaining a particular sequence and timing of technological progress. In these circumstances, considering only prices to provide a whole explication about a complex process underestimates the relevant influences from additional variables that encourage technological progress, molding a market's incapacity (Rosenberg 1976, 3–4).

Dosi (1982) and Dosi and Nelson (2013) accord with this market instruments' weakness to select the technological directions *ex-ante*. Particularly Dosi (1982) emphasizes that this weakness is amplified at the initial stage of the advance, stressing the relevance of an institutional pull for technological progress. Given the market inability, there is an increasing relevance for institutions to construct 'bridges' between basic science and applied R&D. These

bridging institutions are created by governments aiming to influence the directions of a technological paradigm being featured by a capacity to direct efforts for some trajectories of the technological progress. Consequently, there is a relevant role for governments aiming to influence the development or even the acceleration of a particular technological trajectory (Dosi 1982, 155).

In this case, governments may mobilize public forces to accelerate the technological progress in order to deal with a particular issue, prioritizing the research efforts of a determined technological trajectory. One example of the public encouragement for technological development is through military programs that lead the development of microelectronics technologies after World War II. Another example involves a government changing the energy prices or even relative energy prices, directly influencing consumers' preference (Dosi 1982).

According to Dosi (1982) historical examination of the process of selection and the emergence of new technologies concerning a specific paradigm demonstrates the necessity of three crucial elements. First, it is necessary to accumulate knowledge in the forms of both basic research (scientific knowledge) and applied research. In this case, the connection between these forms should be incentivized through bridging institutions, focusing on linking scientific knowledge with its application. Second, some institutional intervention stimulates the application and competition in both technological exploration and manufacturing efforts. Third, a criterion of selection that concern the technological trajectory focuses efforts and concentrates attention on a determined trajectory. In this situation, non-economic interests may fulfill this institutional role, and may include military requirements, energy-saving programs, the national ambition for self-sufficiency in a particular sector, etc. (Dosi 1982, 160). However, it is relevant to emphasize that, even with government agencies or bridging institutions' support, the government action comparable to a "gamble" on a determined technological trajectory based on non-economic objectives (Dosi 1982, 155).

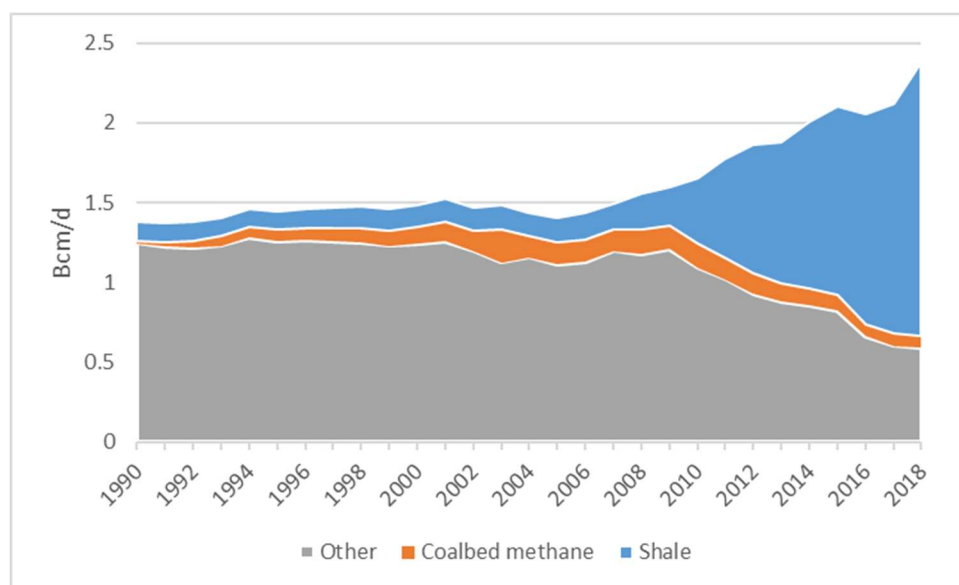
Analyzing the Barnett shale case and Mitchell Energy's performance in regard to HF adaptation, we can affirm that the technological adaptation used for unconventional shale reservoirs derives from close cooperation between public and private sectors. Concerning the government programs, we reference the creation of "Project Independence" after the oil shocks, which include investments delimiting the natural gas resources in unconventional reservoirs; the delimitation of technological challenges concerning the extraction method to be employed; the investments in HF tests on unconventional reservoirs; the participation of Sandia Laboratory (with public resources) developing HF and side-technologies as seismic ones; and,

the direct government involvement providing experiences with shale reservoirs with both HF and horizontal drilling.

2.2 The scale of the unconventional shale reservoirs ‘revolution’ and the country specific context

Natural gas production from shale reservoirs is the main contributor to the US’ natural gas production rebound since 2005. Between 1990 and 2005 (the year marking the beginning of the shale ‘revolution’), the US’ natural gas dry production⁷³ hovers around 1.5 billion cubic meters day (Bcm/d) level. Since 2005, natural gas production has been increasing continuously, passing the historical level of 2 Bcm/d in 2014. Sharing the US’ national dry production sources, the shale participation in production upsurge. Figure 6, below, shows the production evolution that took place between 1990 and 2019.

Figure 6 – US dry production between 1990 and 2018 by sources



Source: IEA (2017b; 2020c).

In the first period, before 2005, production ranges between 1.38 Bcm/d and 1.52 Bcm/d, and shale gas participation in the whole grows slightly from 0.12 Bcm/d in 1990 to 0.15 Bcm/d

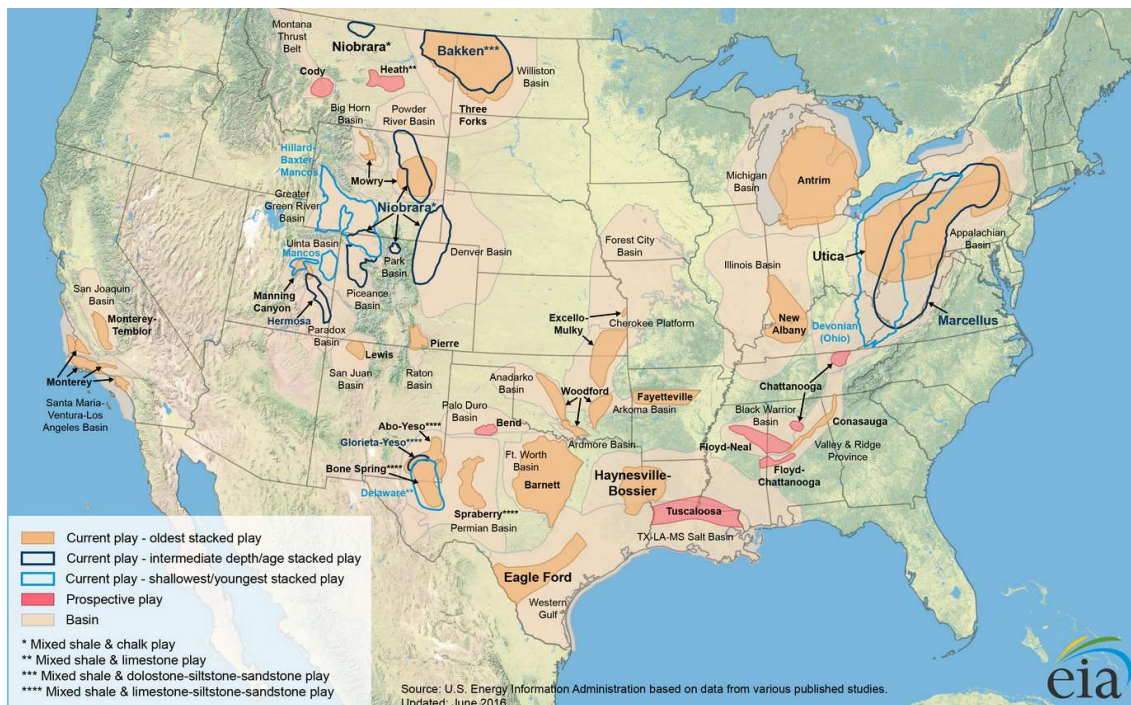
⁷³ Among the possible data representing the US’ production, we have the gross withdrawal, the marketed production and the dry production. The dry production encompasses all the sectorial consumption associated with the transport consumption and the storages balances. The marketed production encompasses dry production plus the extraction losses. The gross withdrawal encompasses the marketed production plus the nonhydrocarbon gases, the reinjections on reservoirs to repressurized them and, venting and flaring (EIA 1991). Among them, we selected the dry production as the best indicator to be compared with the US’ consumption before imports, representing more precisely the US’ production that satisfies its domestic demand.

in 2005. Shale gas production accumulates 25% growth or, on average, 1.5% per year in relative terms. Despite the higher growth rates, this expansion marginally increases shale participation in the national supply, from 8.8% in 1990 to 10.9% in 2005 (EIA 2017b).

In the second period, after 2005, US production exhibits sharp growth, rising continuously from 1.5 Bcm/d to 2.1 Bcm/d in 2015, the shale regions being the critical source of this expansion. From its previous level of 0.15 Bcm/d in 2005, shale production rose to 1.2 Bcm/d in 2015, an average growth of 21.4% per year. This substantial increase in shale gas production multiplies its participation in the total US production by almost five, from 10.9% in 2005 to 56.2% in 2015 (EIA 2017b). This expansion in shale participation associated with its growth over the course of a decade prompts several analyses about shale perspectives, forming the basis for the shale ‘revolution’ terminology.

Figure 7 shows a 2016 map of the US shale plays and includes the different exploratory activities in geological plays.

Figure 7 - Map of US lower 48 states shale plays



Source: Reproduction from EIA (2016).

Figure 7 demonstrates the Barnett shale formation localized in the Ft. Worth Basin in the state of Texas. The Barnett shale is the first unconventional shale reservoir to attain commercial production, being the center of our analysis, as detailed in section 2.4.1.

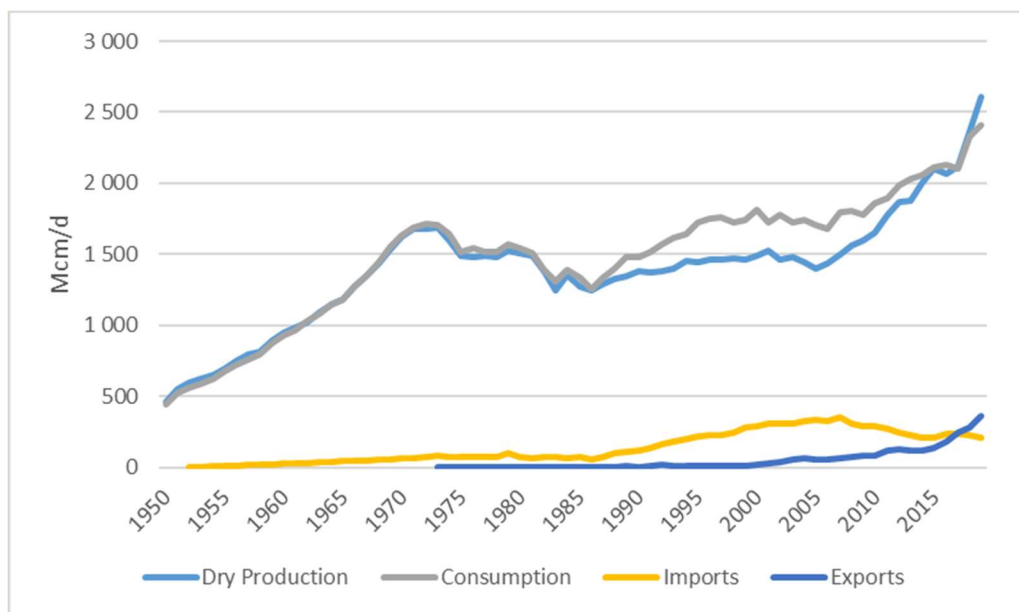
2.2.1 The country context: difficulties to satisfy natural gas demand with national production

From the 1970s until the beginning of the shale gas ‘revolution’ in 2005, the US faced repeated problems of lower growth in natural gas supply than in demand. Occasionally, the mismatch between the growth rates of supply and demand resulted in shortages. Additionally, by the mid-2000s, the US is in a position to become a significant importer of Liquefied Natural Gas (LNG). The following subsection provides more detail about this complex context.

2.2.1.1 The insufficient growth of the US natural gas supply regarding the demand evolution

Comparing the data related to the production, consumption, imports, and exports of natural gas in the US between 1950 and 2019, we can observe the existence of three well-defined phases. Concerning the period between 1950 and 1973, the first phase is characterized by an increase in both supply and demand of natural gas. From 1973 to 2007, the second experienced an initial decline in both consumption and production with a recovery of the previous consumption levels after the 1990s that was based on increased imports. From 2007 onwards, the third phase features continuous growth in consumption, production, and exports. All three phases are observed in Figure 8, below.

Figure 8 – US natural gas dry production, consumption, imports, and exports between 1950 and 2019



Source: EIA (1978, 51; 2020c).

Observing the three phases in more detail and, comparing natural gas dry production and consumption between 1950 and 1973, the latter increases faster than the former, explaining

the necessity of raising imports to satisfy demand. Thus, in 1952, the imports start, reaching an average of 0.61 Mcm/d and increasing quickly to achieve the level of 80 Mcm/d by 1973. In relative terms, imports' participation in total consumption increases from 0.1% in 1952 to 4.7% in 1973 (EIA 1978, 51; 2020c).

The second phase (1973-2007) is characterized by an initial decrease in both dry production and consumption. However, after the 1990s, consumption recovered to its previous level, and was primarily supplied by increasing imports, which achieve 357 Mcm/d in 2007. In proportional terms, imports represent almost 20% of the country's consumption in 2007 (EIA 2020c).

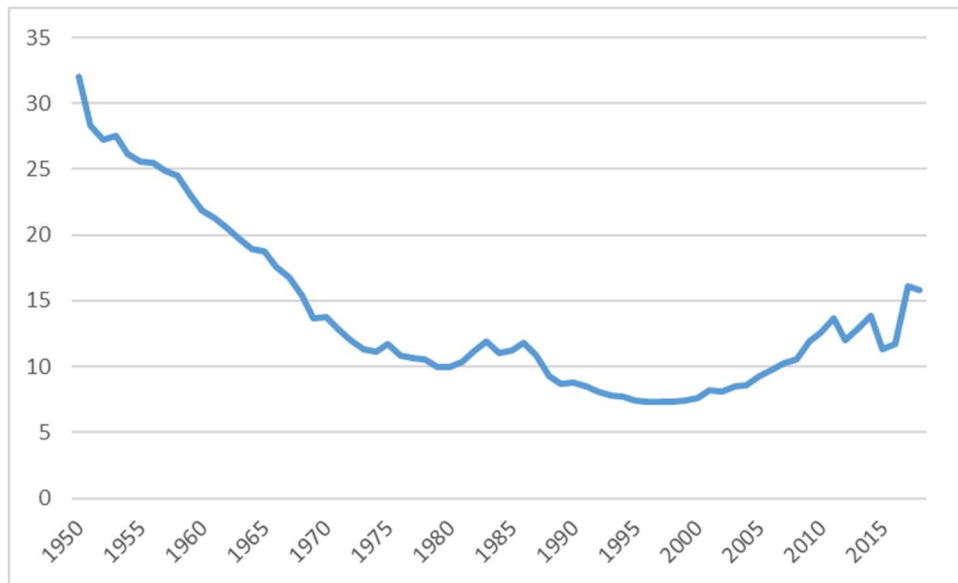
The third phase (2007-present), is characterized by a strong increase in both consumption and dry production, being associated with a decrease in imports. As previously observed, production growth is based on the exploitation of unconventional shale reservoirs. In this period, it is noteworthy that, in 2017, the substantial increase in exports overcame the import level for the first time in US history. Observing the import level in 2017, despite its increases compared to the 2007 volume (to 361 Mcm/d in 2019), in proportional terms concerning national demand, it decreases to less than 9% of total consumption (EIA 2020c).

2.2.1.2 The deterioration of the R/P indicator

In the analysis of the dynamics between national supply and demand another indicator is the ratio between reserves and production, also known as R/P. The R/P is an essential indicator for analyzing how national sources can supply domestic demand, keeping the actual extraction pace. This indicator illustrates in how many years the reserves will be exhausted, assuming the current production and reserves levels.

In the US case, until 2000, there is a continuous deterioration of this indicator. Figure 9, below, demonstrates the evolution of R/P for the US between 1950 (marking the first reserves data) and 2018 (the last).

Figure 9 – The R/P indicator for the US between 1950 and 2018



Source: EIA (2020c).

Figure 9 shows that between 1950 and 2000, there is a continuous deterioration in the R/P, from values higher than 30 to the lowest level of the time series of 7.6 in 2000. This indicator unveils a troubling situation concerning the exhaustion of the national natural gas reserves in 2000 that has been progressing since the 1950s due to insufficient reserve discoveries compared to the current production level. Looking at both reserves and production, we conclude that exploratory activity was not at the same pace as extraction, exposing further resource exhaustion.

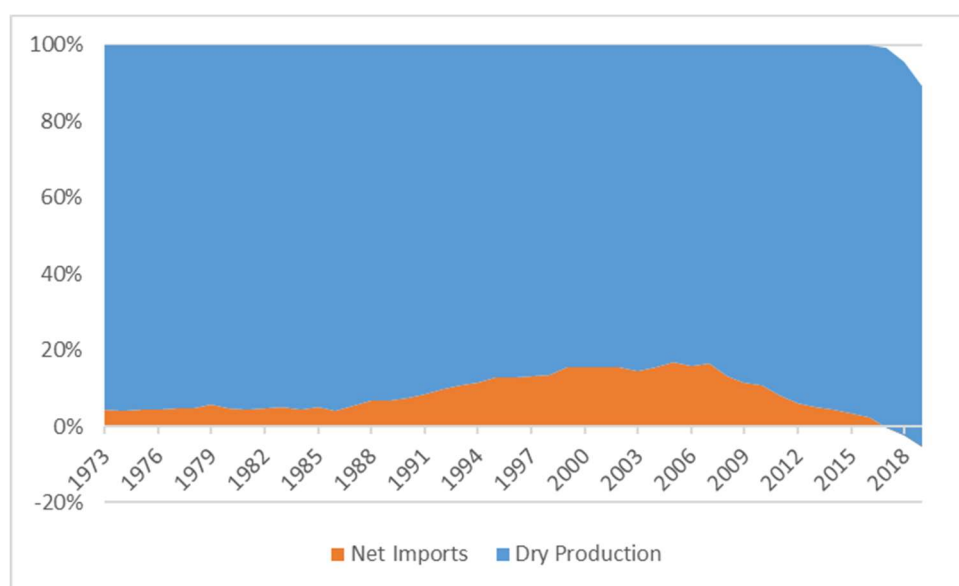
In these circumstances, associating the R/P indicator with the supply and demand data exposed in the previous section, we conclude that, at the beginning of the 2000s, the expansion in the national production is conjugated with an insufficient increase in the national natural gas reserves to replace the current extraction. Analyzing the tendency of supply and demand associated with the R/P indicator, US external dependency on natural gas has intensified since the 1970s.

Nonetheless, since 2000 the beginning of the successful extractions from unconventional shale reservoirs start to improve the R/P indicator. From levels lower than 8, it progressively increases, by 2018, to more than 15. This improvement is directly associated with the shale 'revolution'.

2.2.1.3 The shale 'revolution' reducing external dependence

From 1973 (the first year of data for natural gas exports) until 2007, there is a tendency to increase the external natural gas dependence that is associated with a growing import volume. However, since 2007, this tendency reverses due to increased export volumes. Observing the global figure, there is a net reduction in external dependence (calculated considering the proportion of net imports needed to satisfy domestic consumption). Figure 10, below, provides more details about these movements.

Figure 10 – US natural gas dry production and net imports between 1973 and 2019



Source: EIA (2020c).

In this large period of time, external dependence presents two remarkable movements. Between 1973 and 2007, it progressively increases, from an average hovering around 4.7% in the 1970s, it expands to 5.2 in the 1980s and 11.3% in the 1990s. In 2007 it achieved a peak of 16.4%, progressively decreasing since then. After reaching a peak in 2007 coinciding with the import peaks (at the level of 357 Mcm/d), external dependency quickly falls, achieving net export in 2017.

Consequently, we can conclude that, until the shale 'revolution', US natural gas demand growth is satisfied by increasing imports, which amplifies external dependence. However, since the successful exploitation of unconventional shale reservoirs, the reliance on imports to satisfy national demand has been reducing, by 2017 eliminating external dependence when export overcomes import.

2.2.2 The price control resulting in successive imbalances in the natural gas market

Before the outbreak of the shale 'revolution', the increasing external dependence to supply national energy demand is mostly due to natural gas prices being kept relatively low since the 1950s by government control. On the one hand, low natural gas prices promote the growth of demand. On the other hand, they discourage the necessary investments in additional reserves to provide further supply. The following section provides more detail about the regulatory framework concerning the price control.

2.2.2.1 The regulatory framework

The Natural Gas Act (NGA) of 1938 sets the early involvement of the US federal government in the natural gas market, determining natural gas prices in 'just and reasonable' terms to consumers of interstate pipelines. At that moment, the pipeline companies act as a natural gas merchant, buying fuel from producers and delivering to the local distributors or even the final consumers, meaning a pipeline company charges their clients for both the commodity and the transport service. The association of a free market on wellhead natural gas prices and control on interstate pipelines creates an 'incomplete' regulation of the final fuel price. Thus, dealing with this 'incomplete' regulation, the US Supreme Court decides in 1954 to expand the regulatory power under the NGA to encompass wellhead prices of natural gas destined for interstate pipelines⁷⁴. Seeking to regulate the final natural gas' price to prevent any market power throughout the whole chain, the Court's decision creates two markets inside the US with a delimitation given by the producer state's borders (OECD and IEA 1998, 71–72; MacAvoy and Pindyck 1975, 11–12).

After the Court's decision, once natural gas is extracted, if a producer sells the fuel outside of its origin state, i.e., through interstate pipelines, its wellhead price is under a regulation operationalized by the Federal Power Commission (FPC). If sold inside the producer state, i.e., through an intrastate pipeline, its wellhead price is free of any regulatory constraint.

The US natural gas market being divided in two introduces the possibility of different price movements and reflect several regional and national elements. On the one hand, the intrastate market allows wellhead price movements to indicate local circumstances as the balance between supply and demand associated with any infrastructure limitation or even an eventual market power from pipeline company or producer. On the other hand, the 1954 Court decision extended the NGA parameters of justice and reasonability to determine wellhead price controls

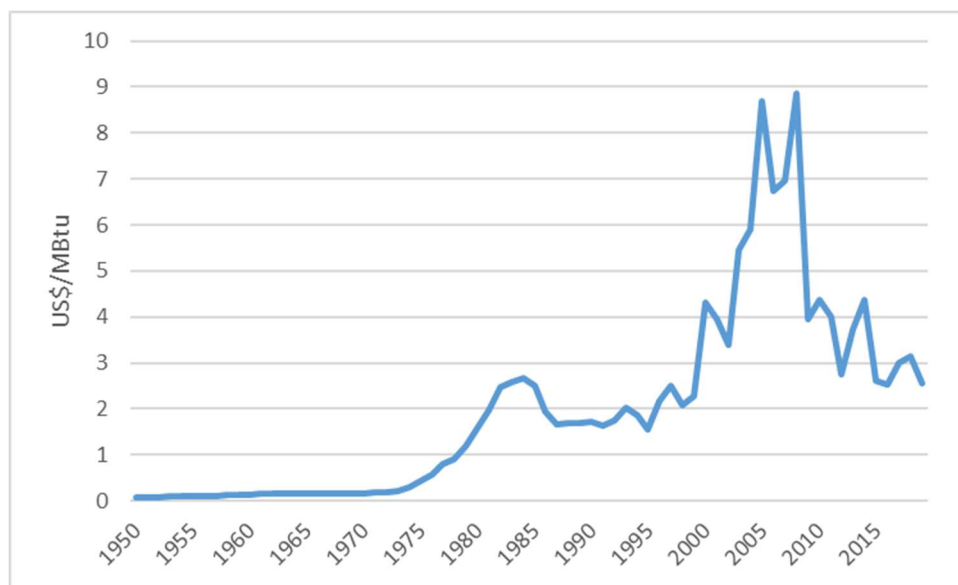
⁷⁴ The decision is named the Phillips Decision, a ruling about the conflicts between Phillips Petroleum and the Wisconsin State.

on the interstate market. Notwithstanding, producers are free to allocate their production for inter or intrastate markets, making companies chose the market presenting the higher price.

2.2.2.2 The natural gas price control resulting in market imbalances

Decades of price controls keeping natural gas prices below their substitute levels resulted in a combination of declining production, fast exhaustion of the national reserves, and undesirable shortages. Additionally, decades of relatively low natural gas prices stimulated consumption and discouraged E&P activities, resulting in decreasing national production. The price dynamics is showed in Figure 11, below.

Figure 11 – US natural gas nominal prices in annual average between 1950 and 2019



Source: EIA (2020c).

Figure 11 shows that natural gas prices (between 1950 and 1997, wellhead natural gas prices, and since 1997, Henry Hub prices) present remarkable stability until the 1990s, when compared with their volatile behavior after this period. At first glance, we can share the price movements in three main phases. Between 1950 and the beginning of the 1970s, the first is featured by prolonged stability. After 1970 until the beginning of the 1990s, natural gas prices present a progressive increase, nonetheless without volatility. Remarkable in this second movement is the price spike between 1979 and 1984 that is followed by relative stability from 1985 on. Since the 1990s, after market liberalization, the third movement is distinguished by higher volatility associated with a double peak in 2005 and 2008, when prices almost reach an annual average of US\$ 9 per Million British Thermal Unit (MBtu).

Instead of examining only the natural gas price dynamics, we can compare this fuel price with that of other fuels by measuring their energetic equivalence, i.e., in the British Thermal Unit (Btu). Looking at possible fossil fuel substitutes for natural gas between 1950 and 1972, like coal and oil, demonstrates that these fuel prices are consistently higher than natural gas prices (EIA 2019b).

In 1950, natural gas prices represent 15.7% of oil prices and 32.1% of coal prices; in other words, for the same cost of buying 1 MBtu of natural gas in 1950, a consumer can buy 0.157 MBtu of oil or 0.321 MBtu of coal. In 1972, the proportion reached 31.6% for oil and 55.5% for coal. Although the price comparison is not for final consumers, i.e., it does not encompass the transport fee and other charges, it demonstrates a relevant economic advantage of consuming natural gas instead of coal or oil⁷⁵.

This advantage in relative prices for natural gas explains its rapid increase as part of the US primary energy consumption between 1950 and 1972. Natural gas achieves an accumulated growth of 280.3% or on average 6.3% per year while, in the same period, the first energy source, oil, reaches 147.4% representing an average of 4.2% per year and, the third, the coal, achieves an accumulated decrease of -2.19%, representing an average of -0.09% per year⁷⁶ (EIA 2019a).

2.2.2.3 The consequence of the control in natural gas prices: shortages in the winters of 1975-76 and 1977-78

As previously predicted by MacAvoy and Pindyck (1975), natural gas shortages under the price control circumstances were a question of time⁷⁷. Consequently, during the winter of 1975-

⁷⁵ The comparison is between the coal free-on-board (FOB) prices, wellhead natural gas prices, and the domestic first purchases for crude oil (EIA 2019b).

⁷⁶ There is a slight variation in the data between the primary energy consumption in Btu and natural gas consumption in its volumetric measure previously quoted. While the first data refers to an accumulated growth in the same period of 280.3%, natural gas consumption achieves 282.2%. We assume that this variation of less than 2% is a result of the conversion to Btu or the exclusion of any natural gas volume, as for example, the gas utilized to repressurized reservoirs, the delivery lost on reinjection/stocks flows, the gas vented or flared, extraction loss, etc. However, to proceed with the exam, we opted to quote the consumption data available by EIA emphasizing this small difference in the information.

⁷⁷ Studying the US' case one year before the first shortage, MacAvoy and Pindyck (1975) defend the real possibility of a further natural gas shortage because of price regulation, primarily based on what the authors named 'prices freezing'. Despite the absence of shortages, the authors affirm that keeping the actual price policies, until 1980 the US will face an inevitable shortage, majorly on consumer states served by interstate pipelines. Thus, the shortage on consumers' states is a result of wellhead prices' regulation at low levels associated with the deregulated prices on producers' states. According with the authors, to prevent the shortages, the regulated price should increase to a level close to the marketing clearing (i.e. intrastate prices), restricting demand at the same time that it increments supply. Finally, another possible solution stated is the prices deregulation, allowing supply and demand interact to set a market clearing price (MacAvoy and Pindyck 1975).

76, the US faced a gas shortage affecting more the interstate pipelines than the intrastate pipelines. The country's separation into two markets creates the possibility for producers to allocate their output to the market with a higher price, in this case, the intrastate market.

In this context, consumer states faced a gas constraint, while producer states virtually did not suffer. However, producer states experienced a fast and robust price escalation because of the absence of the price ceiling mechanism⁷⁸. The 1975-76 winter marks the beginning of natural gas shortage in the US with a second shortage affecting consumer states in 1977-78 (OECD and IEA 1998, 71–72; NPC 1987, 34–35; MacAvoy 1979, 819). The first gas shortage severely affected society, resulting in the closure of public facilities like schools and federal buildings to force a reduction in consumption. In 1977-78, natural gas restrictions were even higher than in the previous years, putting this issue at the center of public debate⁷⁹ (Griggs 1986; Kuuskraa and Guthrie 2002).

2.2.3 The government answer for the supply concerns: the frontier zones development

The increasing external dependence to fulfill national energy demand, before the outbreak of the shale 'revolution', induces several national government policies, which have significant consequences for the future development of frontier zones based on unconventional reservoirs. At the outset of the first oil shock in 1973, the US government reacted by launching "Project Independence". This project aimed to eliminate US' reliance on external sources of energy by developing high-cost production areas, i.e., frontier zones encompassing unconventional shale reservoirs. Additionally, other government programs and tax incentives were put in place to accelerate natural gas production and the technological adaptation in unconventional reservoirs. The following section deeps the government's role concerning the frontier zones development.

This development aims to reach energy independence previously intended by "Project Independence" (Jones and Strahan 1985, 156–57). In such a context, FPC created a task force proceeding with a national survey that concluded in the enormous potential production from

⁷⁸ Analyzing the successive prices increases during the 1970s in the natural gas market, NPC (1987) argues that the major parcel of this increase is due to the intrastate' prices in lieu of a parallel increase in the two markets prices. According with NPC, the intrastate price increases more than 70%, while the regulated interstate price grows only 20% (NPC 1987, 34).

⁷⁹ Griggs (1986) presents several studies with forecasts and estimations for natural gas shortage showing that it achieves some point between 12.7% and 26.8% of the total natural gas demand (Griggs 1986, 818).

unconventional reservoirs encompassing highly tight rocks, establishing frontier zones as a possible solution for the US' natural gas supply issues.

The task force focused on the Devonian-age shales in the Appalachian Basin, and described a massive quantity of O&G resources locked in source rocks having exceptionally low permeability⁸⁰ (tight) with challenging geology, resulting from a poorly understood and studied history (Kuuskraa and Guthrie 2002, 76–77). The task force concluded in the existence of 17 Tcm of natural gas locked in these unconventional reservoirs, of which 40 to 50% could be recoverable through the creation of extensive fractures. We stress that in 1978, only the identified reserves from unconventional reservoirs (ranging between 6.8 Tcm and 8.5 Tcm - 40% to 50% of the total *in situ* resources of 17 Tcm) are higher than the total US proven reserves, of 5.94 Tcm (EIA 1978, 61).

Referring to the definition established in the first chapter, beginning with the 1970s, we can classify these tight reservoirs as frontier zones. The low level of E&P activities to gather both experiences and information about the production methods justify its classification as a low level of knowledge. The level of knowledge supports the magnitude of the risk, classifying these formations as high risk, mainly based on technical-economic risks instead of geological one. Despite the resource presence, its economic viability depends on the capacity to unlock the resources from their tight reservoirs.

According to the task force, the country was plentiful in natural gas resources. Still, it could not economically extract them without overcoming technological challenges represented by identifying and adapting the 'correct' techniques. Thus, from a government perspective, the acceleration in unconventional reservoirs' exploitation was necessary to face all the gloomy forecasts relative to the natural gas market.

[Assessing unconventional reservoirs resources: the government role](#)

A study conducted by the National Petroleum Council (NPC) (1980) emphasizes the unconventional shale and tight gas reservoirs' relevance for providing further supply in the US. The study identifies the potential recoverable reserves considering different price scenarios, sharing unconventional reservoirs according to the source. For all of the US sandstone tight reservoirs, the potential ranges between 5.4 Tcm and 16.2 Tcm. For the shale resources in the

⁸⁰ The usual metric for the reservoirs' permeability is the Darcy. While in conventional reservoirs this metric is calculated on milli-darcy (md) ranging around hundreds, in shale reservoirs, a kind of the tight reservoirs, it varies between "a few hundred nano-darcies (0.0001 md) to a few milli-darcies (0.001 md)" (EIA 2013, 2-18;19). In other terms, these reservoirs are so tight that its permeability is calculated on nano-darcy instead of the usual hundreds of milli-darcy for conventional ones.

Appalachian basin, the recoverable resources range between 0.09 Tcm and 1.4 Tcm. Despite that both reservoirs are classified as unconventional and use the same stimulation technique to enable their production's flow (i.e., HF), the tight sandstone lower thickness guarantees its advantage. This lower thickness assures a better wells' productivity after HF when compared with the shale reservoirs. Thus, while the tight sandstone reservoir could continue their exploitation at the 1980s prices, the shale remains a potential further reserve. The exploitation of shale reservoirs depends on additional circumstances, such as additional price increases or technological advancements reducing its costs⁸¹ (NPC 1980).

Nevertheless, we emphasize that from the previous estimation of 17 Tcm of *in situ* resources in unconventional reservoirs, the NPC's study reveals the initial studies' underestimation about the unconventional resources potential. According to the NPC study in 1980, the total recoverable resources from these two unconventional reservoirs range between 5.5 Tcm in the worst scenario to 17.6 Tcm in the best scenario. This estimation is higher than the previous forecast made by the FPC's task force in 1972 for the total US unconventional resources, in which the value ranges between 6.8 Tcm to 8.5 Tcm for recoverable resources (40 to 50% of the 17 Tcm *in situ*). It is noteworthy that the NPC study considers the whole tight reservoirs and only one basin of the shale reservoirs, disregarding other unconventional resources. In contrast, the FPC's task force estimates the entire US' unconventional reservoirs potential.

2.2.4 The definition of the technological challenge to reach the commercial exploitation of unconventional reservoirs

Luetkehans (1976) emphasizes that the development of unconventional reservoirs will be expensive with results only in the long term. These high costs are mostly related to the technological challenges of overcoming the reservoirs' tightness. The necessary investments for unlocking these resources through technological adaptation to the tight reservoir environment represents a high risk investment.

⁸¹ The shale's scenario considers three different technological applications in five different price scenarios. The first technology is the traditional method of only shooting the wellbore, the second is the utilization of HF, and the third is a technological advancement on the HF method, allowing a higher recoverability factor. Considering prices, they vary between US\$ 2.5 MBtu and US\$ 9 MBtu. As expected, lower prices are associated without the application of HF, resulting in a lower recoverability factor. Higher prices are associated with improvement on HF's technology, resulting in the higher recoverability scenario (NPC 1980).

To increase the wells' productivity and, consequently, elevate a resource's recoverability, it is necessary to employ some extractive methods such as HF and horizontal wells⁸². While these two techniques did not represent disruptive innovation that change the technological paradigm⁸³, nonetheless their application in the tight reservoir environment brought about several obstacles that demanded a sequence of technical adaptations and advances on correlated technologies representing a technological advancement.

The necessary advances in technological adaptation are already delimited through a 1976 debate by the Board on Mineral Resources organized by the National Academy of Sciences (NAS). From this debate, five major points to adapt the massive HF to the unconventional reservoir environment arise, emphasizing technological obstacles faced by pioneers to increase the production flows through the utilization of the HF technique. Advances in HF enhances the recoverability factor expressed by the wells' productivity, having positive effects on unconventional reservoirs' economic viability (NAS 1976).

[Five obstacles to adapting HF technique to unconventional reservoirs in the 1970s](#)

The NAS hosted a debate about the US' natural gas issues in 1976 with specialists to delimit the difficulties and shed light on further paths to extracting the resources from unconventional reservoirs. These debates delineate five main obstacles linked with the adaptation of HF as an extractive technique in unconventional reservoirs.

The first obstacle is to increase the control in the orientation of the fractures inside the reservoirs. In 1976, HF unconventional reservoirs generates vertical fractures instead of the desirable horizontal propagation. In vertical wells, the target is to propagate the fractures to expose higher reservoirs' areas to the wellbore. Additionally, this vertical tendency on fractures

⁸² In the words of the Board on Mineral Resources analyzing unconventional shale resources in 1976: "The challenge is to find practical ways to produce it [unconventional reservoirs], and that may be difficult. However, in view of the history of successful production in eastern Kentucky and western west Virginia, and possible new techniques, such as **directional drilling** and **hydraulic fracturing**, the prospect is encouraging." (NAS 1976, 6 emphasis added).

⁸³ HF as well as horizontal drilling or the downhole motors were not frontier technologies when adopted on unconventional reservoirs. While the first horizontal well is completed in 1937 in Russia with a total horizontal distance of 91 meters, the first HF is completed in US in 1947 and its utilization was widespread to the industry in 1949. Even Mitchel Energy utilized the HF technic during an exploratory campaign in 1952 with its first big discovery. The utilization of downhole motors improves the directional control of the well, being this technology applied since the first horizontal well drillings. However, just on the outset of the 1980's, horizontal drilling reaches its viability with encouraging results from BP and Elf technic utilization (Stevens 2010, 11; Joshi 1991, 8–16; Wang and Krupnick 2013; Kutchin 2001, 17–19; Gold 2015, 92).

increases the probability of connection among them, reducing the drainage area and, consequently, the efficiency of HF (Elkins 1976, 133–36).

The second challenge is to develop a technique to manage the fracture height and its lateral extension. There were difficulties with the available technology to guarantee that the fracture expands in the previously determined size and its lateral extension inside the reservoirs (Elkins 1976, 133–36).

The third deterrent to the HF approach is the improvement of technologies to visualize the fracture's propagation. In other words, there is a necessity to develop surface and subsurface passive mapping mechanisms to improve the evaluation of the fractures' propagation in the reservoir. This kind of technology will optimize HF utilization on tight reservoirs (Randolph 1976, 164).

The fourth difficulty is connected with the models utilized to compare the wells' results with the theoretical approximation. Confronting the theoretical model with the practical inputs may improve the HF process, influencing the production rates positively. However, in 1976, the models present a limited capacity to explain the HF process and their influences (Elkins 1976, 133–36).

The fifth and last obstacle is linked to natural gas prices. The 'correct' natural gas prices may increase private interest, raising the number of investors involved with the unconventional reservoirs' obstacles in order to attain commercial production. While in 1976, only between 15 and 20 companies were involved with HF development, they were justified by the intrastate natural gas contracts that attained higher prices than the interstate contracts. Thus, in a deregulated market presenting higher prices, the incentives to resume investments and the number of companies would be even higher, also increasing the development pace of the HF technique (NAS 1976, 186).

2.3 The government instruments to mitigate the frontier zone risks in the US' unconventional shale reservoirs

To face the supply problems associated with increasing energy dependence, the US government developed several initiatives aiming to ramp up national natural gas production. Although these initiatives did not directly target developing unconventional shale reservoirs, they enhanced the extraction from high-cost regions through two elements: increasing the natural gas prices to guarantee the investments' profitability; and accelerating technological

progress. Both elements mitigate frontier risks, being assessed through the evolutionary theory and the historical institutionalism, as previously summarized by Figure 5.

This thesis identifies that the US government employed three instruments to mitigate technical and economic risks of frontier zones: institutional reorganization of the regulatory framework; financial support; and cooperation with the private sector. On the one hand, reforms in the regulatory framework and the financial support allowed higher natural gas prices, mitigating economic risks of high costs zones. On the other hand, cooperation between public and private sectors allowed the acceleration of technological progress. Each of these instruments contributed to developing frontier zones based on unconventional shale reservoirs. These instruments handling the frontier zones' risks associated with it's the specific implementation's context are the center of our analysis.

Reorganizations of the regulatory framework molded a reform trajectory focusing on liberalizing the natural gas price formation. These reforms gradually increased the natural gas prices favoring the development of unconventional shale reservoirs, assuring the investments' profitability and, consequently, reducing economic risk. Following Bezes and Palier (2018), and Thelen (1999), this thesis identifies the reform trajectory through a long term analysis connecting the reform's origins and its sequence. This analysis demonstrates a reform trajectory focused on liberalizing the natural gas price formation that resulted in a gradual increase in prices. Indeed, while the reforms of the regulatory framework are motivated by several imbalances in natural gas markets (from shortages to oversupply), its sequence reveals a gradual progression to liberalization in the price control.

The financial support focused on increasing the E&P activities in high cost areas, including unconventional reservoirs, mitigating economic risks associated with these activities. The financial support for high costs zones is materialized through higher prices (during the period of the government price controls), tax credits, and subsidies.

Our analysis reveals the government involvement to mitigate the technological risks through several forms of cooperation between the public and private sectors. This cooperation is based on the structuration of several organizations focusing on accelerating technological development concerning the adaptation of both HF and horizontal drilling methods on unconventional reservoirs. Thus, we conclude in a governmental effort focusing on achieving a double objective. First, at the initial stages of the technological development, the government associated with the private sector in order to define the most appropriate technological trajectory concerning the extractive techniques needed to exploit unconventional reservoirs,

concluding in the technological trajectory incorporating both HF and horizontal drilling. Second, the government stimulated private actors to engage in technological advancements focusing on unlocking unconventional resources trapped in tight reservoirs through operational tests with both HF and horizontal drilling. The association between these initiatives encouraged additional productive investment in these regions, increasing the involvement of actors interested in achieving higher profits. Thus, it demonstrates that the government applied a focusing force to accelerate the technological development, as previously emphasized by the evolutionary theory (Rosenberg 1976; Dosi 1982; Dosi and Nelson 2013). The following section deepens our analysis of the US' case concerning the government instruments.

2.3.1 The gradual reforms molding a trajectory for market liberalization

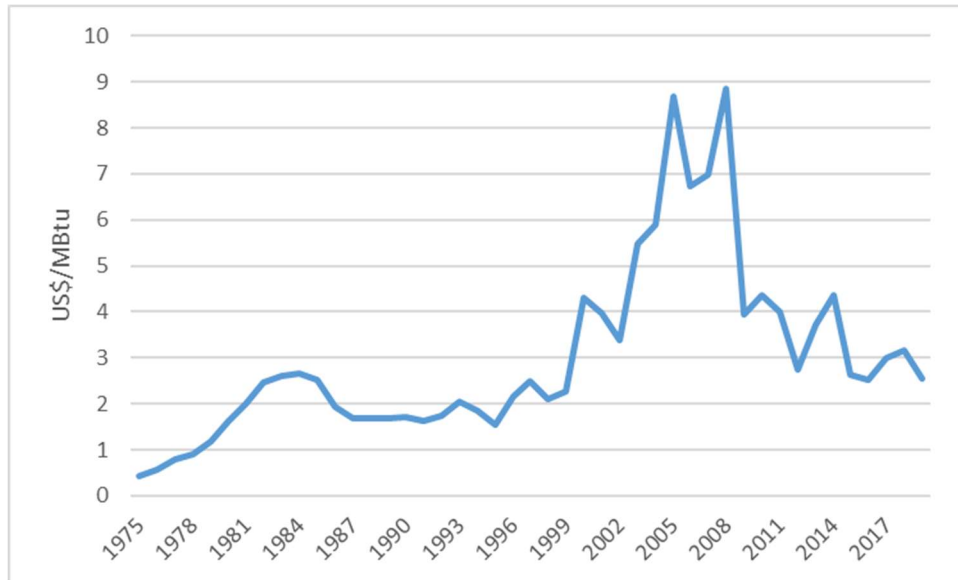
Although price increases mitigate economic risks associated with frontier zones, we emphasize that the regulatory framework's reorganizations do not focus on developing frontier zones. Indeed, examining the reforms' origins demonstrates that they are focused on solving imbalances in the natural gas market, primarily connected with shortages in the 1970s and the oversupply in the 1980s. Despite this initial driver, examining the reforms' sequence demonstrates a connection between them, leading the government to articulate an institutional change to prevent the adverse effects of market imbalances. This articulation resulted in several reforms, shaping a trajectory leading to market liberalization centered on the price formation mechanism, allowing the market dynamics between supply and demand to generate the equilibrium price.

The reformulation in the price controls mechanism, starting in the 1970s and being complete in the 1990s, is associated with an increase in the natural gas price, leaving the previous orientation centered on the affordability of natural gas for consumers. We emphasize that this is a gradual movement corresponding to an institutional change through a progressive alteration in the rules bounding the actor's behaviors. Consequently, this gradual institutional change is reached through a governmental effort to reformulate the regulatory framework adding new orientations and rules and resulting in successive increases in the natural gas prices.

Higher natural gas prices are a determining factor for the profitability of investments in frontier zones by mitigating economic risks. The intricate regulatory framework demanded successive reforms to avoid the identified issues, resulting in a gradual increase in prices. From shortages to oversupply periods, the reforms focused on changing the price controls mechanisms, altering the orientation from a 'just and reasonable' natural gas price for a price reflecting the current circumstances between supply and demand (market liberalization). This

identified reform trajectory focusing on liberalizing the price formation mechanism can be visualized in more detail in Figure 12, below.

Figure 12 – Annual average of the Henry Hub prices between 1975 and 2019



Source: EIA (2020c).

Figure 12 shows a progressive increase in natural gas prices before the shale ‘revolution’, from averages values under US\$ 2 MBtu until 2000, it substantially increased. Since 1997 there is a progressive increase in prices with a double peak in 2005 and 2008 when the Henry Hub prices almost attained an annual average of US\$ 9 MBtu. Comparing this peak with the previous historical values, it is a substantial increase, demonstrating that the liberalization in price formation mechanism achieved after the reforms in the regulatory framework allowed the market’s dynamics (interaction between supply and demand) increases the natural gas price previously to the shale ‘revolution’.

The following section provides a historical institutionalism analysis of the regulatory framework reforms molding a trajectory leading to liberalization in the natural gas price formation. The successive reforms allowed an increase in natural gas prices, reducing economic risks of frontier zones, including unconventional shale reservoirs. The reforms encouraged investments for developing additional sources to satisfy the national demand for natural gas, ensuring private investments' profitability. The price increases generated a significant incentive to accelerate the development of high production costs areas as the frontier zones. Consequently, we concluded in a progressive reorganization in the regulatory framework producing a reform trajectory liberalizing the price formation encouraging actors to intensify investments in frontier zones.

2.3.1.4 The reform's origin: the successive shortages of 1975-76 and 1977-78

Facing two successive shortages during the winter season after the first oil shock⁸⁴, as previously observed in section 2.2.2, the US authorities raise the controlled prices to reach parity with the non-regulated price's level balancing supply and demand⁸⁵. Consequently, the average wellhead nominal prices rise from US\$ 0.44 MBtu to US\$ 0.91 MBtu between 1975 and 1978. Comparing with their peers considering the calorific power, in 1978, natural gas price level achieves 56.6% and 89.6% of oil and coal prices, respectively (EIA 2019b; 1991).

This natural gas price increase is accompanied by a reformulation in the price formation methodology⁸⁶, justified by both elements the first oil shock⁸⁷ and the natural gas shortages. This is the first reformulation in the regulatory framework concerning the price formation mechanism, however without changing the price orientation based on both elements, justice and reasonability for consumers.

In this context, the US authorities proposed a reformulation in the regulatory framework, the NGA, concentrating the attention on avoiding further natural gas shortages. Targeting this objective, this reform on the natural gas regulatory framework changes the price control orientation from 'just and reasonable' price for consumers to a price encouraging the

⁸⁴ The first oil shock is a direct support from the Organization of Petroleum Exporting Countries (OPEC) to the Egypt and Syria war efforts against Israel and their allies during the *Yom Kippur* war in 1973. Viewing the US as an Israel supporter, the OPEC engages in a reduction of their oil supply, constraining their production each month until the Israel's borders come back to the limits establish before the 1967 war, named '6-days war'. Thus, geopolitical events were the major determinant of the first oil shock although the existence of economic reasons through the limitation of supply to attain higher oil's economic rent (Hamilton 2011, 14; Yergin 2013; Fattouh and Mahadeva 2013, 5; NPC 1987, 44–46).

⁸⁵ Another solution is to limit the growing demand for natural gas or even replace it by other fuels as the ambition proposed by the National Energy Plan created on the Carter's government in 1977. Despite the several propositions, a soften version is enacted by the Power Plant and Industrial Fuel Use Act of 1978. The previous ambition was to ban the construction of any new electric power plant using as primary energy source oil or natural gas. Notwithstanding, the Act determines that new facilities running with oil and natural gas also have to forecast an additional capacity to switch the primary energy source to coal or other alternative fuel. In practical terms, this demand substantially increased the construction costs of these facilities, almost forbidden the construction of them based on natural gas or oil (Gordon 1979; US 1978, Part A—Prohibitions; US DoE 2019).

⁸⁶ Between 1954 and 1960, FPC chose to regulate the prices by a 'cost-of-service' rate, making each producer to receive an individual rate based on individual costs. The quantity of producers and, subsequently, individual rates create a huge task for FPC. Thus, in 1960 FPC decides to set the rates sharing the country in five regions with different natural gas prices ceilings. Faced with a challenging reality on oil prices and increasing obstacles to regulate wellhead prices through the 'cost-of-service' methodology, the FPC changes the price's control in 1974, adopting a national ceiling for interstates sales.

⁸⁷ Subsequently of the first oil shock, the natural gas prices tendency changed from a real net reduction to constant rise, doubling between 1973 and 1975, from US\$ 0.22 MBtu to 0.44 MBtu.

development of the domestic supply through additional E&P investments (Griggs 1986, 72; MacAvoy 1979; Joskow 2013). The following section describes the reformulation in more detail.

2.3.1.5 The reform changing the prices' orientation targeting to prevent further shortages

In 1978, the Natural Gas Policy Act (NGPA) replaces the previous NGA to balance the natural gas market while still maintaining the prices under government control. The NGPA introduces two main modifications in the natural gas market.

First, it handles the country's intricate regulation sharing it on two markets, breaking-up the inter and intrastate barrier by expanding the regulator's power to the whole pipelines and wellhead prices. In other terms, the NGPA unifies the US market under the national price control of the Federal Energy Regulatory Commission (FERC), replacing the functions of FPC.

Second, it changed the price formation orientation focusing on encouraging investments in E&P, mostly through a progressive movement in natural gas wellhead prices to market-clearing levels. In this case, the Act allows FERC to establish national prices ceiling according to a new principle to stimulate the E&P investments, majorly that focused on frontier zones (OECD and IEA 1998, 71–72; Joskow 2013, 338–39; MacAvoy 1979, 819–21).

The successive rises in regulated wellhead prices to restrain demand and increase supply permits to the natural gas price moves toward a market-clearing level. Instead of proceeding with an open liberalization, the NGPA aimed the full deregulation for new production in 1985, i.e., in seven years⁸⁸. In these circumstances, the NGPA is the first regulatory framework envisioning a price mechanism based on balancing supply and demand, foreseeing a progressive market liberalization. The parcel of natural gas subject to the liberalized market will gradually increase according to the increased participation of new wells. According to this progressive deregulation, the NGPA allows FERC to establish several national price ceilings depending on the wells' age and other elements representing its costs⁸⁹ (Griggs 1986, 72–73; MacAvoy 1979, 819–21).

Thus, FERC establishes different price ceilings considering the wells' age and the costs to extract natural gas. In this context, to stimulate the previously identified high extractive cost

⁸⁸ By new production, the NGPA defines the wells drilled after the act. Additionally, the NGPA leaves the old wells without a perspective to be deregulated.

⁸⁹ The price ceiling varies according with: "the date a well was started, the depth of the well, its proximity to other wells, whether the gas was committed to the interstate market on or before November 8, 1978, the date the well began production, and the geology and geography of the deposit from which the gas was produced." (EIA 2009b).

region, FERC authorizes an even higher price ceiling for them, including the production from unconventional reservoirs (more detail in section 2.3.2) (Griggs 1986, 72–73; MacAvoy 1979, 819–21). Following the new price's orientation, FERC resumes the price escalation that has been happening since 1974 on nominal prices, lasting until 1984. In nominal terms, from a level of US\$ 0.29 MBtu in 1974, it increases continuously until 1984, achieving US\$ 2.66 MBtu. Considering this period, it accumulates an increase of 786.6% or an average of 24.39% per year. In real terms, the growth achieves 341% or an average of 16% per year (EIA 2019d; 1991).

2.3.1.6 The oversupply demonstrating the necessity of additional improvements in the regulatory framework

After the double natural gas shortage, FERC increased the natural gas price creating an oversupply period. The 1986 year marks the 'oversupply', represented by the lowest import levels associated with the lowest natural gas participation as a primary energy source in the US. This oversupply encourages consumers to switch from natural gas to other fuels, progressively reducing the natural gas demand. To avoid an even lower natural gas demand, the pipelines companies authorized qualified consumers (that with the enough capacity to change the fuel) to purchase natural gas directly from producers, restricting its actuation to transport the molecule. This new kind of contract exposed a discrimination between consumers by its capacity to change the fuel, demanding an improvement of the regulatory framework to avoid the consumer's discrimination. In these circumstances, the prices' control shows another undesirable feature, mobilizing the government to accelerate prices' liberalization.

Compared with other fossil fuels, the increasing natural gas price motivates large consumers to substitute the most expensive natural gas by coal. Despite the necessary initial investment, this change is profitable, given the difference between the fuel's prices. To discourage a massive fuel switch, increasing its effects on demand, companies running natural gas pipelines create a different kind of contract named Special Marketing Programs (SMPs). Under the SMPs, consumers with the financial capacity to change their fuel could obtain natural gas directly from producers, accessing lower prices after the oversupply period.

On the one hand, the SMPs expose the discrimination among consumers by their capacity to switch their energy source, allowing these qualified consumers to access the fuel at lower prices, paying only the transport fee to the pipeline's companies. On the other hand, the SMPs unveil a conflictual relation of the pipelines' companies, acting simultaneously as merchants and transporters. While a gas transporter requires a remuneration for their previous investment constructing the pipeline, the gas merchant desires a low competition delivering the molecule

directly to end-consumers. Thus, there is a conflict in the pipelines companies acting simultaneously as merchant and transporter. In this context, several Court's decisions demand pipeline companies to finish the discrimination materialized by the SMP (Joskow 2013; FERC 1992, 5; Griggs 1986, 82–89).

Despite the determination to vanish with the SMPs contracts, FERC analyses the positive effects for consumers from these contracts and the conflictual role of pipelines' companies, reformulating their regulatory scope based on this experience.

Therefore, through several Orders between 1985 and 1992, FERC determines unbundling the whole US' natural gas pipeline infrastructure (more detail in Box 6, below). In this case, instead of finish with the discrimination among consumers, FERC defines the SMPs' logic as a rule for the whole natural gas market, adding non-discriminatory access to the transport's service. The non-discrimination discourages any competitive advantage from the pipeline control over other natural gas merchants demanding a transport service through the pipeline, guaranteeing access on an identical basis to the pipeline transportation system (FERC 1992, 6–7). This rule allows consumers to obtain natural gas directly from producers utilizing pipelines to transport the commodity. In the context of falling natural gas prices and a stable transport fee, the consumers reaches a significant cost reduction (OECD and IEA 1998, 71–72; Joskow 2013, 339).

Box 6 – Orders 436 and 500 improving the regulatory framework in the natural gas market

In 1985, FERC enacted Order 436, authorizing the voluntary change of interstates pipelines purpose. From the main role of a natural gas merchant, it could assume the sole purpose of a transporter, connecting the production sites to the commodity's final destination, charging the natural gas owner by the transport services. Additionally, this Order forbidden the pipeline's companies to deny access based on the protection of its merchant services, thus equaling the pipeline companies to any other demand for commodity transport. Despite the Order's voluntary framework, in 1987, 26 of 45 major pipelines representing 78% of the operating revenues agreed to change their role from a merchant to a transport company (US GAO 1987, 11–29).

However, as pipelines' companies took several 'take-or-pay' contracts for long-term natural gas purchases with higher prices than the spot one, they face low demand levels associated with a long-term position acquired in the context of natural gas shortages. Thus, pipeline companies 'shut-in' several producers wells given its lower demand and, at the same time, face a reduction in their consumer basis. To settle the problematic judicial discussion between pipeline companies and suppliers about the responsibility of 'take-or-pay' contract resolution (Griggs 1986, 79–80), FERC enacts the Order 500 in 1987, encouraging pipeline companies to buy-out their take-or-pay contracts. This Order allows the pipeline companies to pass a portion of the cost (between 15% until 75% of the buy-out) to the pipeline's transport fees (EIA 2009a).

2.3.1.7 The complete deregulation in the price formation mechanism due to successive market imbalances

The successive imbalances of natural gas propel additional reform in the US gas market. In particular, the price's control demonstrates its incapacity to balance the market, enhancing further supply concerns.

In these circumstances, the US authorities enacted the Natural Gas Wellhead Decontrol Act (NGWDA) in 1989. This Act foresees a schedule to completely deregulated natural gas wellhead's prices until the beginning of 1993.

However, in practical terms, the impact of the Act is insignificant because of two factors. First, in 1989 the deregulated wellhead prices are below the regulated one. Second, more than 60% of the whole US' production is already deregulated in 1989 (from them, 33% was never regulated by the NGPA) (OECD and IEA 1998, 71–72; Joskow 2013, 339; EIA 2009c). Nonetheless, the Act formalizes the deregulation direction, guiding the agents to a new reality of market-clearing prices instead of a regulated one.

2.3.2 Two additional stimulus for high-costs regions: tax credit and higher natural gas prices

As a first reaction to the second oil shock⁹⁰ in 1980, the US Congress enacts the Crude Oil Windfall Profit Tax Act to deal with the windfall profits obtained by national oil producers. The Act focuses on mechanisms to redistribute the windfall to high extractive cost producers resulting in additional incentives for the national production (US 1981, 26–27; Knoll 1987, 166).

The definition of a windfall profit is a gain obtained unexpectedly and without any effort of an agent, usually being an exogenous action increasing its profit. The term has its origins during the American revolutionary war that occurred in the XVIII century. To guarantee the necessary wood for the construction of warships, the British government banned its use for any civil purpose. However, if by an 'act of God' materialized by storms, strong winds, or other forces, a tree falls within a private property, the landowner can confer property to the wood and use it freely. Thus, the fall of trees had granted considerable profits within the context of war

⁹⁰ The second oil shock is marked by two different but associated geopolitical crises in Iran and Iraq. In the final months of 1978, the Iranian revolution terminates with the monarch starting a theocratic government. Previously, the US considered Iran as a relevant ally being a reliable source of oil once the country was the single main oil exporter that does not participate of the 1973 oil embargo. Increasing the crisis, Iraq starts a war against Iran the aftermath the revolution, tightening oil market due supply constraints from two relevant oil exporters (Hamilton 2011, 17–18; Yergin 1993; 2013).

efforts that diminishes this raw material's availability, originating the term windfall profits (Johnston 2004, 8).

The Crude Oil Windfall Profit Tax Act establishes a tax associated with a credit to redistribute the windfall gain from the oil shock. While the tax depends of the difference between the market price and the corrected price⁹¹, the tax credit reaches a value of US\$ 3 per barrel for high cost regions. As a mechanism to stimulate new investment in the E&P activities, only new wells are apt to receive this credit, being it in force between 1980 and 2002⁹². The tax credit is also applied to the high extractive cost regions producing natural gas, utilizing Btu's energetic equivalence to make the conversion. The Act defines the natural gas high cost regions, encompassing the geopressured brine, Devonian shale, coal seams, and tight formations (US 1981, 26–27; Knoll 1987, 166). Thus, wells drilled on unconventional shale reservoirs until 2002 could apply to this tax credit.

After this Act, producers from high-cost regions could apply for a tax credit of US\$ 0.54 for each MBtu of natural gas⁹³. In relative terms, as wellhead price for natural gas reaches, on average, US\$ 1.53 MBtu in 1980, the tax credit attains a value higher than 1/3 of the current wellhead natural gas prices (Stevens 2010, 13; Wang and Krupnick 2013, 7–10; Kuuskraa and Guthrie 2002, 78–79; US 1981, 80–82). Nonetheless, the progressive increase in natural gas prices had reduced the stimulus in proportional terms. Considering that in the 1990s, the annual average of natural gas price reaches US\$ 2.16, the tax credit achieves 1/4 the current price.

Higher prices for unconventional reservoirs

Considering the period previous to market liberalization, when the government established the natural gas price, FERC authorized a higher price for high-cost regions after the NGPA. We observe a substantial incentive for high cost areas from the EIA data through an ample price differential.

For the first year with available data, 1981, wellhead natural gas price reaches an average of US\$ 1.98 MBtu (price for wells drilled before the NGPA, meaning 'old' wells). For new wells

⁹¹ The Act shares oil in three tiers. Each tier has its tax rate based in the difference between the price obtained in market and the 'adjusted' base price set by the federal government considering a state severance adjustment (Knoll 1987, 166; US 1981, 27–41).

⁹² Just wells drilled after December 31, 1979 and before January 1, 2002 were elected by this tax credit (US 1981, 80).

⁹³ Assuming that each oil barrel has 5.551365 MBtu and receives US\$ 3 per each barrel, it represents US\$ 0.54 for each MBtu of natural gas or oil. According with Stevens (2010), in 1992, this credit increases to US\$ 0.94 per thousand cubic feet (Stevens 2010, 13), meaning US\$ 0.97 per MBtu, considering that each thousands of cubic feet of natural gas has 1.036 MBtu (EIA 2019f).

(drilled after the NGPA), the price reaches US\$ 2.89 MBtu. For high-cost regions, the price is even higher, achieving US\$ 6.58 MBtu, a value 232% higher than the average price (EIA 1991, 177). These prices differentials are detailed in Table 5, below.

Table 5 – Prices differentials between 1981 and 1992

Year	Wellhead prices			Percentual difference from	
	Average	New Gas	High Cost Gas	Average	New Gas
1981	1.98	2.89	6.58	232%	128%
1982	2.46	3.19	7.31	197%	129%
1983	2.59	3.43	6.25	141%	82%
1984	2.66	3.65	5.35	101%	47%
1985	2.51	3.62	4.71	88%	30%
1986	1.94	3.11	3.48	79%	12%
1987	1.67	2.65	2.72	63%	3%
1988	1.69	2.41	2.61	54%	8%
1989	1.69	2.46	2.53	50%	3%
1990	1.71	2.35	2.47	44%	5%
1991	1.64	2.28	2.58	57%	13%
1992	1.74	2.29	2.1	21%	-8%

Source: Based on EIA (1991, 177).

Table 5 reveals that between 1981 and 1992, there is a significant difference between the average price for natural gas from ‘old’ wells, new wells, and high cost areas. Until 1991, the wells from high cost areas also obtained higher prices than the new areas. However, the price stimulus for high costs areas, including unconventional shale reservoirs, is gradually reduced. While the price’s difference from new wells is practically finished since 1987, it remains significant when compared with ‘old’ wells.

Although this price differential through the 1980s and the beginning of the 1990s, market liberalization finished with this specific benefit for high cost regions. In such a context, since 1993, the only financial support for high costs zones is the tax credit created in 1980 by the Crude Oil Windfall Profit Tax Act, lasting until 2002.

2.3.3 The public and private sector cooperation accelerating the technological progress

As previously emphasized in section 1, the evolutionary theory relating to the focusing forces stress the government's relevance prioritizing some technological trajectory instead of others (Dosi and Nelson 2013; Dosi 1982; Rosenberg 1976). In the US case, this thesis identifies this prioritizing through the allocation of government resources, channeling the private sector to the technological trajectory incorporating HF and horizontal drilling on unconventional reservoirs. Consequently, we observe a government effort to select the appropriate technological trajectory and, after this selection, accelerate the technological progress

supporting both basic R&D and the introduction of the advances. The association among all these elements shapes an effective cooperation between the public and private sectors, constructing an operative partnership shaping an environment focused on introducing technological advancements to attain higher productivity from exploiting unconventional reservoirs.

Analyzing the US case, it is remarkable that the progressive governmental actuation defines the technological trajectory and stimulates actors to engage in technological development. The US government provided financial resources to test different extractive techniques (nuclear and HF), defining HF as the appropriated trajectory. Since this definition, the government has increased its involvement providing financial resources to adapt the HF method and horizontal drilling on unconventional reservoirs. Finally, the organization of bridging institutions connecting basic research to actors' problems actively encourage tests to introduce technological advancements in unconventional reservoirs. In these circumstances, the shale 'revolution' is molded by creating a cooperation with the private sector, demonstrating a direct government involvement and support, choosing the trajectory, and accelerating the technological progress as previously stressed by Figure 5.

After the delimitation of the unconventional reservoir's potential and the technological challenge linked with the extractive technique in the 1970s, the government provided additional financial resources to delimit the appropriate technological trajectory concerning the exploitation of unconventional reservoirs. Among the methods to improve the flow of natural gas listed by the task force (that identified the potential of unconventional reservoirs), there are HF and nuclear explosions. Nonetheless, the tests to improve the flow rate from unconventional reservoirs with both techniques are virtually inexistent. To compare the methods, the government provides financial resources to test both methods on unconventional reservoirs.

The nuclear technique is applied on unconventional reservoirs through three tests utilizing resources allocated to the Plowshare Program⁹⁴. HF is tested on unconventional tight

⁹⁴ Luetkehans describes three successive experiments with nuclear explosives to stimulate natural gas production from tight reservoirs. The first in 1967 use a 29 kiloton explosive in the San Juan basin in New Mexico state. The second in 1969 use a 43 kiloton explosive in the Piceance basin, in western of the Colorado state. The positive results of both experiences stimulate the third one in the last location (Luetkehans 1976, 169). A government report gives more information about the Plowshare Program and their nuclear tests to fractured the tight rocks. The program focused on utilizing nuclear explosives on industrial applications, being their application aggregated on two large types: "1) large-scale excavation and quarrying, where the energy from the explosion was used to break up and/or move rock; and 2) underground engineering, where the energy released from deeply buried nuclear explosives increased the permeability and porosity of the rock by massive breaking and fracturing." (US DoE n.d., 4)

sandstones reservoirs with Energy Research and Development Administration (ERDA) resources associated with 15 American companies. While ERDA provided financial aid according to its objective to encourage extracting national energy sources⁹⁵, private companies focused on technical support.

The test with massive HF happened in the Piceance basin west of the Colorado state⁹⁶ in 1975. Albeit the results with HF are worse than the previous experiments with nuclear explosions, the participants chose HF as the appropriate technique to develop, directing the technological trajectory to resume the exploitation of unconventional reservoirs. This option by HF instead of the nuclear approach is based on public opinion, notably linking the nuclear explosions with possible accidents (Kuuskraa and Guthrie 2002, 76–77; Luetkehans 1976, 174–75).

Despite this first government involvement supporting the tests to select the appropriate extractive technique for exploiting unconventional reservoirs, technological development has a high cost based on the research effort with uncertain future results. Therefore, a debate hosted by NAS in 1976 provided two main conclusions shaping the future government strategic action. First, associated with the HF method, the horizontal wells approach also has to be adapted for the exploitation of unconventional reservoirs. Second, the research efforts related to the adaptation of these extractive techniques have to be supported by the government. In the NAS words: *“Efforts to develop cheap effective means for producing gas from these presently underdeveloped resources should be encouraged and imaginative ideas subsidized.”* (NAS 1976, 9–10). In other terms, the experiments with HF and horizontal drilling should be financially supported by the government (NAS 1976, 9–10; Kuuskraa and Guthrie 2002, 76–77).

After this discussion in NAS, the US Congress provides funds for three programs centered on unconventional extraction managed by the Department of Energy (DoE)⁹⁷ under the

⁹⁵ In the aftermath of the first oil shock, the government creates the ERDA to develop national energy sources, including unconventional shale reservoirs.

⁹⁶ The basin is located on the states of Colorado and Utah, being frequently quoted with its neighborhood basin, Uinta given its similar geological formation (Johnson, Chan, and Konopka 1992).

⁹⁷ The Carter administration consolidate the several energy agencies and bodies created in the aftermath of the first oil shock to combine the US' efforts in a single department, the DoE. Thus, in 1977 the DoE is created encompassing several initiatives to handle energy. Among the agencies and departments, the DoE incorporated the Energy Research and Development Administration (ERDA), the Federal Energy Administration (FEA) and, the Energy Planning and Policy Office and Energy Emergency Action Group (Jones and Strahan 1985, 158–60).

Unconventional Gas Research Program (UGRP)⁹⁸. This program is designed to encourage the exploitation of unconventional reservoirs introducing technological advancements sharing research costs with private investors. The program has the specific goal to develop “(...) *technologies for recovering new gas supplies from the massive but complex unconventional gas resources – tight gas, coalbed methane, gas shales, and geopressured methane.*” (Kuuskraa and Guthrie 2002, 76–77).

The UGRP helps to drill 35 wells on unconventional formations of the Appalachian basin⁹⁹, encouraging a full understanding of this region's physical and chemical characteristics, explored by small and independent producers. Furthermore, it sponsors the research on relevant technologies founding the shale ‘revolution’ as the microseismic fracturing mapping with Sandia Laboratory¹⁰⁰, and additional development on massive HF (delimiting the further potential concerning the utilization of this technique). Finally, the program was also responsible for the first horizontal well in the Devonian formation, setting the bases for introducing it on other unconventional reservoirs (NETL 2007, 12).

Another governmental initiative is the authorization to establish the Gas Research Institute (GRI) in 1976. The GRI is a non-profit institution focused on applying technologies throughout the gas industry, playing a bridging institution's role. Despite its private feature, GRI funds are obtained through a surcharge on natural gas flows in interstates pipelines, previously authorized by the FPC (NETL 2007, 14–15).

The GRI provided financial support for the introduction of technologies related to unconventional reservoirs. Additionally, George Mitchell, the owner and founder of Mitchell Energy, was director of this institute, which helped him orientate the technological development and keep him updated with frontier technologies on unconventional reservoirs exploitation (Gold 2015, 84–85).

⁹⁸ This program is divided in three projects: Eastern Gas Shales Project (EGSP) focused on Devonian-age shales from eastern US; Western Gas Sands Project (WGSP) focused on low permeability gas sandstone reservoirs (also named tight sandstone reservoirs) from the western US; and, Methane Recovery from Coalbeds Project (MRCP) focused on coal seams (NETL 2007, 12).

⁹⁹ The Appalachian basin is named by its characteristic Appalachian systems of mountains. The basin crosses 10 US' states (New York, Pennsylvania, Ohio, West Virginia, Maryland, Kentucky, Virginia, Tennessee, Georgia and Alabama), covering near 480,000 km². Notwithstanding, now-a-days the basin is well know to host the Marcellus shale, one of the most productive natural gas producer in the US (EIA 2017a).

¹⁰⁰ Sandia National Laboratories is a private research center working for the DoE.

The association of all these governmental initiatives generates an environment of cooperation between the public and private sectors focusing on the technological development to increase the extraction from unconventional reservoirs. The progressive government involvement in selecting the appropriate technological trajectory and accelerating the research efforts shape the government cooperation with the private sector. Finally, the multiple feedback and linkages between public and private sectors that jointly defined both the technological trajectory and the research efforts are noteworthy.

2.4 The Barnett shale as the first successful unconventional reservoirs exploitation: an analysis of its learning curve

This section analyses the shale 'revolution' origins to understand the process of introducing a technological advancement overcoming the obstacles of frontier zones. Thus, we identify the first region in the US that reached commercial production from unconventional shale reservoirs, delimiting our case study to the Barnett shale region. To provide an analysis of this region, as previously emphasized by the analytical framework summarized by Figure 5, this thesis takes as theoretical support the evolutionary theory concentrating on examining two mechanisms mitigating the technological risks: the regional learning curve; and the risk aversion of companies introducing technological progress.

Previously, in section 2.1.2.2, we defined the learning curve concept incorporating both intentional and interactive learning. Interactive learning is represented by the learning by doing, revealing the agents' capacity to improve productivity according to the production level, in this case, E&P activities in unconventional shale reservoirs. Intentional learning incorporates the heuristic of research, its cumulateness feature, R&D efforts, and the multifaceted feedbacks between firms and the market.

Consequently, the investigation concerning the learning curve has to ponder several elements varying from the companies' specific features (as its risk's aversion), the environment, and the market. From this complex environment, this thesis investigates two main elements to characterize the regional learning curve. First, the E&P activities, incorporating by the number of active wells in the region and the total production. These indicators are condensed through the average wells' productivity revealing the accumulation of knowledge (or the degree of understanding) from the adaptation of HF and horizontal drilling methods in this region. Second, the regional market environment corresponding to the companies acting in the market and its risk aversion, investigating the multiple feedbacks between companies and the market. In this case, we assume that the degree of risk aversion of companies in the O&G sector accords to

company type, taking as metric the traditional classification of international oil company (IOC), national oil company NOC and independent. The companies operating in the Barnett shale case are exclusively independent.

Independent companies, operates only in the E&P chain of the O&G sector (upstream). According to Al-Fattah (2013), a typical independent company is a firm established for many years with a relatively small business when compared with an IOC and habituated to manage a project without partnerships. Independent companies are less risk averse, accept higher risks according to further higher profits, being risk-taking companies (Al-Fattah 2013, 8).

According to Dosi (1982), introducing a technological advancement in the market has two phases, the emergence and the maturity (better detailed in section 2.1.2.4). The emergence is featured by a high risk relating to introducing a technological improvement demanding a risk-taker company to manage the process. The maturity corresponds to the competitive phase when other players start to catch up with the leading company's achievements.

In our study of the Barnett shale region, we assume that the process of introducing HF and horizontal drilling follows the dynamics previously described by Dosi (1982). Thus, we investigate critical periods in the technological adaptation, focusing on analyzing the learning curve achievements. We assume that the wells' productivity peaks signalize the technological adaptation's crucial periods focusing our attention to these periods. We delineate two regional development phases of the Barnett shale case associating these peaks with the natural gas prices.

Our analysis of the first learning curve stage in the Barnett case demonstrates that the leading company, Mitchell Energy, continuously improved the HF technique through a trial-and-error process, testing several solutions focused on reducing costs and increasing the wells' productivity. Thus, as previously described by Dosi (1982), this phase corresponds to the emergence of a leading company accepting to take risks through a trial-and-error process aiming to introduce technological progress.

We emphasize the Dosi (1982) explanation about the company's risk aversion in the first phase corresponding to introducing technological progress. Given the uncertainty of this phase, the presence of a firm accepting to take risks is necessary, being these risks admitted by the possibility to appropriate higher profits. The leading role in the Barnett shale region is played by Mitchell Energy, an independent company in the natural gas sector accepting these risks to appropriate higher profits.

The second learning curve stage in the Barnett shale is featured by increasing competition between several companies resulting in a continuous reduction of the leading role. In the context of rising natural gas prices, the leading company introduces the horizontal drilling technique to improve the shale reservoirs' recoverability factor. The positive results from the introduction of HF and horizontal drilling associated with increasing prices encourage other players to catch-up with the leading company and its achievements in technological adaptation, molding the second phase (the industry maturity) as previously described in Dosi (1982).

The following section offers more detail about the regional learning curve, being shared in four subsections. The first delimit and justify our object of study, the Barnett shale region. The second defines the development phases of the Barnett shale. The third describes the first learning curve stage in the Barnett shale. The fourth characterizes the second learning curve stage.

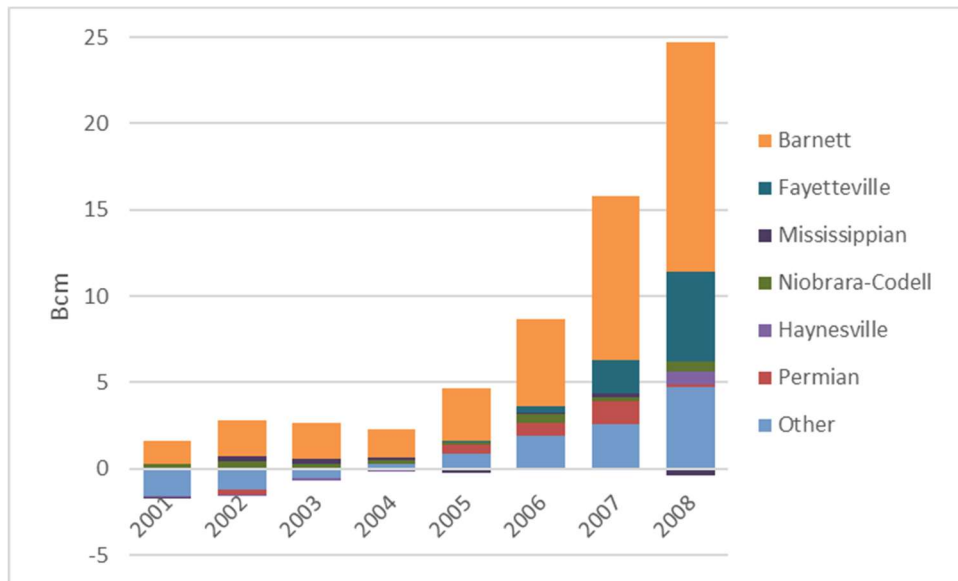
2.4.1 The Barnett region leading the shale 'revolution'

From all shale production regions between 2000 and 2008¹⁰¹, the Barnett region demonstrates its relevance in the origins of the 'revolution' (GWPC 2009; Cameron et al. 2018; Middleton et al. 2017; Stevens 2010; Anderson 2013; Steward 2007; Bowker 2007; Wang and Krupnick 2013; Harper 2008). From all the US' shale gas regions¹⁰², the Barnett increases its weight from 5.2% in 2000 (5.3 Mcm/d) to a maximum of 41.7% in 2008 (109 Mcm/d) (EIA 2019c). Another way to observe the region's relevance in the US' shale production between 2001 and 2008 is through the production variation shown in Figure 13, below.

¹⁰¹ As defined in the previously, the shale increasing production starts close to 2005. In this context, the data discriminating the shale regions are available after 2000 and the thesis focus is before the shale 'revolution' outbreaks, meaning a period close to the 2005 year. The analysis of the whole data series (between 2000 and 2018) demonstrates an increasing participation of the Barnett shale with an inflexion point in 2008. In this context, its participation in the whole shale's reservoirs production increases from 5.2% in 2000 until achieve 41.7% in 2008, progressively reducing it to 4.4% in 2018. Since our interest is to reveal the leading region in the beginning of the shale 'revolution' to focus our analysis in a single region, we chose the period between 2000 and 2008 to prevent an extension of the analysis to conclude that the Barnett shale region is the leading of the shale 'revolution'. However, it is relevant highlight that this period associates an increasing on both production, the whole shale production and the Barnett shale, being the key responsible by the increasing production the Barnett shale region.

¹⁰² By shale production regions we are referring to: Marcellus (in the states of Pennsylvania, West Virginia, Ohio and New York); Permian (in the states of Texas and New Mexico); Utica (in the states of Ohio, Pennsylvania and West Virginia); Haynesville (in the states of Louisiana and Texas); Eagle Ford and Barnett (in the state of Texas); Woodford (in the state of Oklahoma); Bakken (in the states of North Dakota and Montana); Niobrara-Codell (in the states of Colorado and Wyoming); Mississippian (in the states of Oklahoma); and, Fayetteville (in the state of Arizona).

Figure 13 – The annual production variation of the leading shale gas regions in the US between 2001 and 2008



Source: EIA (2019c).

Figure 13 shows the production variation (positive values) or reductions (negative values) between 2001 and 2008 for the six central shale gas regions¹⁰³, illustrating the contribution of each to the total US shale production. The primary objective of Figure 13 is to show the Barnett region’s contribution to the increasing output provided by the shale exploitation until 2008. Assessing only the regions presenting an annual net growth on natural gas production from shale reservoirs, the Barnett shale has the lion’s share, overcoming the 50% level between 2001 and 2008. In other words, the Barnett is the first shale region to increase its production substantially, supporting the argument that this region leads the shale ‘revolution’, driving the shale reservoirs to overcome the frontier zone status.

2.4.2 Three development phases of the Barnett shale

This subsection aims to identify the two Barnett shale development phases and the decline phase by examining both natural gas prices and the average productivity by active well¹⁰⁴, or shortly wells’ productivity.

¹⁰³ The sum of these six regions (Haynesville, Barnett, Niobrara-Codell, Mississippian, and Fayetteville) represents, on average, 64.4% of the whole US’ shale gas production between 2000 and 2008. Thus the dynamics on these six regions have the higher explicative power to reveal the US shale gas’ development in this period.

¹⁰⁴ By active wells, we are meaning wells with a production superior to zero.

The association between natural gas prices and the wells' productivity proves to have a high explicative power to disaggregate the region's development phases, given their complementary features. On the one hand, the data from natural gas prices reveals the incentives to E&P investments in the O&G sector. On the other hand, the regional wells' productivity gives the local reaction from these investments¹⁰⁵.

The following discussion is divided in two parts. The first exams the nominal natural gas prices movements while the second scrutinizes the well's productivity movements. By the examination of both factors, we delimit the two development phases. Between 1993 and 1999, the first is characterized by the relative stability of prices associated with a continuous productivity gain. Between 2000 and 2008, The second is characterized by an escalation in the nominal prices related to two peaks in the wells' productivity.

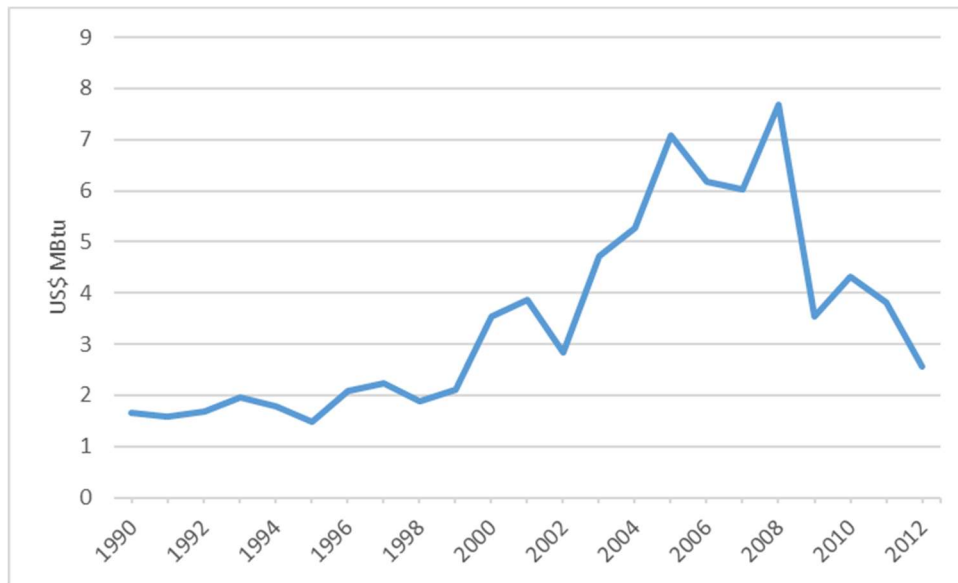
2.4.2.1 The wellhead nominal prices dynamics

Analyzing natural gas wellhead price dynamics between 1990 and 2012¹⁰⁶, there are three different price movements, as shown in Figure 14, below.

¹⁰⁵ Explaining the leading role of the Barnett shale region, IEA declares: "The Barnett shale play in North Texas (around Fort Worth) was the first play that attracted significant development, after experimentation with newer technologies and well designs resulted in consistently higher well productivity." (IEA 2009, 401).

¹⁰⁶ In this case, we highlight that the EIA database stopped to inform wellhead natural gas prices in 2012, restricting our analysis to this year. Instead of replace this data for another, as example, the Henry Hub prices, we chose to limit the data analysis without any relevant loss to this thesis.

Figure 14 – Natural gas wellhead nominal price in the US between 1990 and 2012



Source: EIA (2017b).

The first price's movement corresponds to the years between 1990 and 1999. In this period, natural gas price exhibits a small increase from its initial level of US\$ 1.6 MBtu to US\$ 2.1 MBtu, an accumulated growth of 28% or 2.8% per year (EIA 2017b).

Between 2000 and 2008, the second presents a substantial increment, growing more than three times in nominal value. From an initial level of US\$ 2.1 MBtu in 1999, it substantially increases to US\$ 3.5 MBtu in 2000, keeping its growing pace until achieving the value of US\$ 7.7 MBtu in 2008. In proportional terms, between 1999 and 2008, the nominal natural gas price accumulated an increase of 263.9% or 15.4% per year (EIA 2017b).

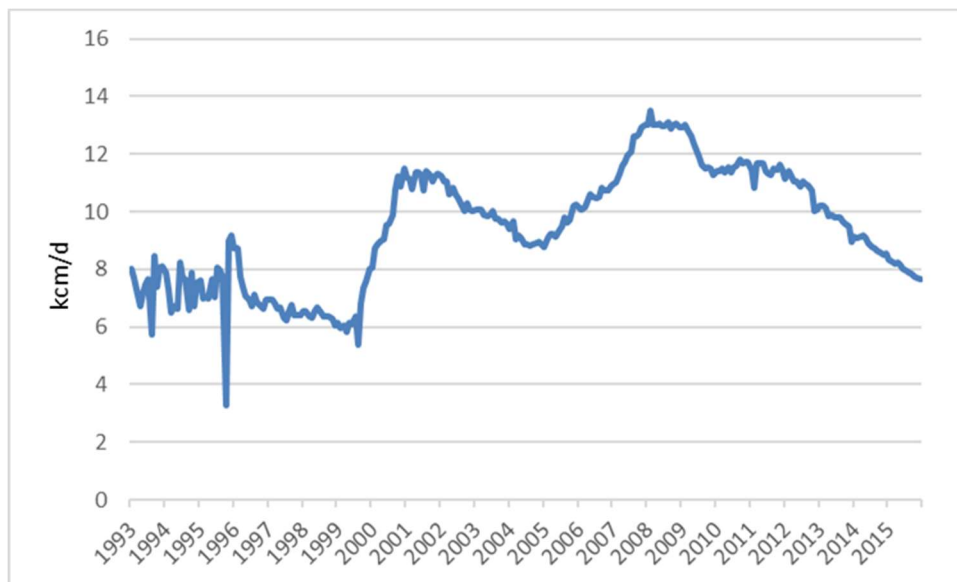
The third movement starts after 2008 and is characterized by a plunge in natural gas prices, from its previous level of US\$ 7.7 MBtu in 2008 to US\$ 2.5 MBtu in 2012. In proportional terms, between 2008 and 2012, the nominal natural gas price accumulated a decrease of -66.6% or -13.6% per year (EIA 2017b).

2.4.2.2 The three wells' productivity movements

Figure 15, below, allows us to examine the wells' productivity between 1993 and 2015, delimiting three phases. While the last period, after 2008, potentially represents the exhaustion

of the resources in this region¹⁰⁷, the two first are of our interest to understand these movements to shed light on the shale evolution, therefore, being the center of our analysis.

Figure 15 – Monthly well’s productivity in the Barnett shale region



Source: Based on RRC (2019).

Between 1993 and 1999, the first phase is characterized by high volatility of the wells’ productivity conjugated with stable natural gas prices. This phase is marked by high volatility around the average of 7 thousand cubic meters per day (kcm/d) with a minimum value of 3.3 kcm/d in October 1995 and a maximum of 9.2 kcm/d in December 1995 (RRC 2019)¹⁰⁸.

Between 2000 and 2008, the second phase is characterized by successive increases in the wells’ productivity associated with a persistent and robust elevation in nominal prices and three wells’ productivity movements. The first movement is an increase in productivity, starting at the end of 1999 and lasting until 2002. It results in establishing a new high production level in the region, when it quickly raises from previous average productivity around 6 kcm/d to more than 11 kcm/d in the final months of 2000, thus, almost doubling the earlier results in less than three years. After this increase, the wells’ productivity presents small variations around 11 kcm/d until the initial months of 2002 when it starts a smooth and continuous decline achieving the lowest

¹⁰⁷ In this case, we adopted the term “potentially” to be cautions around the shale’ resources exhaustion. In this case, we would like emphasize that, given the actual extractive methods, this shale region achieved its potential production.

¹⁰⁸ The dataset encompasses 19 487 wells with more than 170 thousand monthly data over 23 year (January 1993 to December 2015) of production in the Barnett shale from Railroad Commission of Texas (RRC 2019) compiled by Middleton *et al.* (2017).

point in January 2005 at 8.7 kcm/d. After this point, this indicator presents another increase, overcoming the 13 kcm/d level at the beginning of 2008 (RRC 2019).

Finally, the third phase is characterized by a reduction in both prices and wells' productivity, starting after 2008 and lasting until the final of the time series in 2015. It forms a constant decline from its previous level around 12 kcm/d in 2011 until achieving 7.6 kcm/d in December 2015 (RRC 2019).

To conclude, as the thesis focuses on the development phases of the Barnett shale, the last period featuring a reduction in the wells' productivity will be discarded, delimiting the thesis scope to the two first periods of development. Lastly, we assume that the first development phase encompasses the first learning curve stage, while the second one incorporates the second learning curve stage.

2.4.3 The first Barnett learning curve's stage: The role of Mitchell Energy focusing on reducing HF's costs

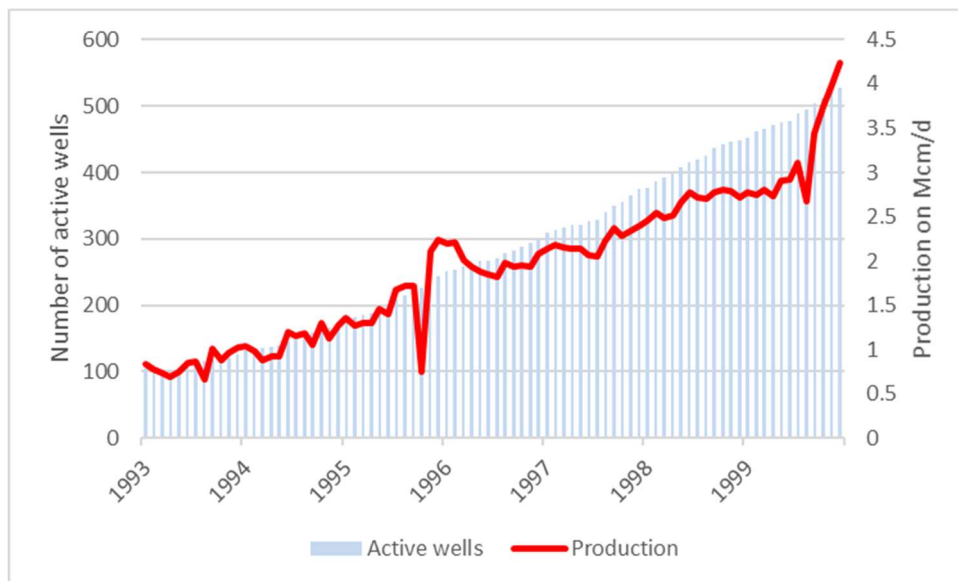
This part aims to scrutinize the first learning curve stage, investigating the reasons for the initial productivity gains in the final months of 1999 in the context of prices' stability. From the analysis of this learning curve stage, we reach two conclusions. First, the initial volatility on the wells' productivity results from HF's experiments based on a trial-and-error approach¹⁰⁹ (IEA 2013, 453). This approach increases the wells' production's unpredictability, raising the variability of the wells' productivity. Second, the final productivity increase is based on technological achievement outlined by the introduction of the Slick Water Fracturing (SWF) approach on the Barnett shale by Mitchell Energy.

Number of active wells and the production in the Barnett shale region

The Barnett shale region's available public data includes the number of active wells and the region's production. We dedicate Figure 16, below, to display both data dynamics between the first learning curve stage.

¹⁰⁹ IEA defines the advance of the E&P activities in unconventional reservoirs by a trial and error or even a hit-and-miss strategy. In its words: "(...) drilling for shale gas or light tight oil remains largely a trial-and-error operation. When moving into a new area, an operator will experiment with different lateral well lengths, different number of fracturing stages, different types of fracturing fluids and different perforation strategies until a combination that provides good economic returns is found. Finding the "sweet-spots", the parts of the reservoir that give good production, is also often hit-and-miss." (IEA 2013, 453). In its 2016 report, it declares that despite all the side technologies to identify the 'hot-spots': "(...) once promising areas have been identified, there is still no substitute for "learning-by-doing", i.e. the knowledge that comes from drilling and completing wells." (IEA 2016, 241)

Figure 16 - Number of active wells and the production on the Barnett shale region between 1993 and 1999 by month



Source: Based on RRC (2019) and Middleton *et al.* (2017).

Figure 16 shows the active wells' evolution through columns (left axis) and the production through a red line (right axis) in the Barnett shale between 1993 and 1999. The total production in the region increases according to the number of active wells, starting 1993 at 0.83 Mcm/d, achieving 4.23 Mcm/d at the final of 1999. In this period, the active wells have been presenting a net growth, increasing its pace continuously.

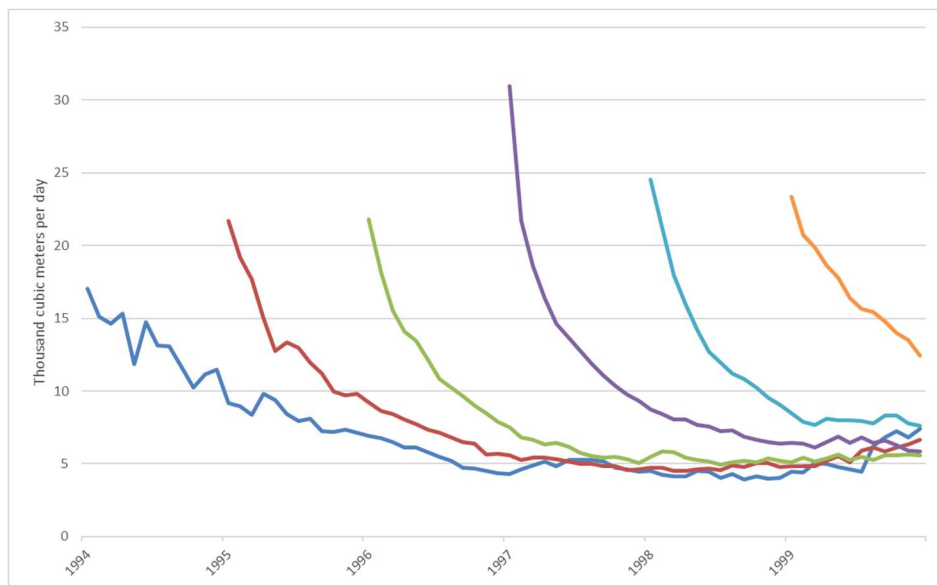
Scrutinizing the increasing production, it is clear that it keeps its growing pace according to the active wells' expansion. However, taking a closer look at these data, in the final months of 1999, more precisely between September and December, there is a substantial increase in the production disconnected with the wells quantity, revealing a wells' productivity gain.

From a previous level around 3 Mcm/d, the region's production achieves 3.4 Mcm/d in September 1999, quickly increasing to overcome 4.2 Mcm/d in December. Observing the active wells', from a value of 495 in August, it progressively increases to 528 in December, making an average of 8 new active wells per month, a growth near the observed between January and August of the same year, of 5 new wells per month, revealing an increasing wells' productivity after September. We dedicate the next part to scrutinize the wells' productivity gains and their reasons.

2.4.3.1 The old wells increasing production as the driver of the 1999's wells' productivity augmentation

Aiming to better delimit the wells' productivity gain in the final months of 1999, we split the data by the year of drilling, resulting in the average production by well considering its year of drilling. The observation of this data provides a piece of valuable information about the average output from wells drilled in a determined year, shedding light on the wells' performance considering their year of drilling and their contribution to the overall wells' productivity. We dedicated Figure 17, below, to show these data, placing the average production in the vertical axis and the years in the horizontal axis. In this case, the lines represent the evolution of the average production in time, respecting the year that a set of wells were drilled.

Figure 17 – Average production from new wells by year of drilling between 1994 and 1998



Source: RRC (2019) and Middleton *et al.* (2017).

The analysis of Figure 17 proportionate two conclusions. First, there is a wells' productivity gain on new wells drilled between 1994 and 1999. It increases from 17 kcm/d to 23 kcm/d, a rise of 6 kcm/d in 5 year, or 35.2% in the first month. Notwithstanding, the year presenting the higher initial average productivity is 1997 when this indicator overcome the 30 kcm/d level. To conclude, despite the incapacity to maintain the production level achieved by the wells drilled during 1997, the examination of the whole period demonstrates a relevant production gain. We assume that this productivity gain is a consequence of the accumulation of knowledge on the Barnett shale based on the increasing E&P's activities in this area in the period.

Second, the substantial increase in the wells' productivity in the final months of 1999 is not only explained by the rise in new wells' productivity gain but in the productivity rebound from wells drilled in 1994. Although the average production of new wells evolves in this period, this metric cannot reveal the leading cause of the wells' productivity gain in the final months of 1999. Examining more closely Figure 17 during the last months of 1999, there is an increase in productivity from wells drilled during 1994 represented by the rise in the 1994-line. More precisely, from a previous level of 4.48 kcm/d, these wells start to augment their average production to 7.64 kcm/d. Additionally, during 1999, there are 47 active wells drilled in 1994. From them, ten wells presented a significant increase in productivity in the final months of 1999, being the primary responsible by the wells' productivity increase in the final months of 1999¹¹⁰.

Only the data analysis is insufficient to understand all the dynamics in this frontier zone. However, it indicates a productivity increase in old wells, drilled in 1994. In these circumstances, an investigation of this production rebound's causes demands an examination of this region's events. This justifies the thesis approach to interpret this increase in productivity from old based on the region's events.

2.4.3.2 The Mitchell Energy leading role in the Barnett shale region

From all available data, we can show that the leading company in the Barnett shale region is a single company, Mitchell Energy. Among the data, the number of active operators, or simple, the operators with a positive production between 1993 and 1999 in the region progressively increase. At the same time, the production shares of the leading company in the area progressively decrease from 95.3% in 1993 to 83.5% in 1999. These data are detailed by Table 6, below

¹¹⁰ From these 10 wells, the most impressive was the well named Peterson, Ruby "A", increasing its production by more than 8 times between July and October 1999. Additionally, all these wells belong to the leading company, Mitchell Energy.

Table 6 - Quantity of active operators and the leader's share on the total Barnett shale production between 1993 and 1999.

Year	Quantity of active operators	Leader's share (Mitchell Energy)
1993	8	95.36%
1994	6	97.21%
1995	8	94.88%
1996	11	93.66%
1997	13	87.29%
1998	12	85.44%
1999	13	83.49%

Source: Based on RRC (2019).

Despite several other companies trying to unlock the O&G's production from unconventional reservoirs distributed across the US, the first region to achieve a substantial shale's production is the Barnett region¹¹¹. Consequently, we can affirm that Mitchell Energy has the leading role in the area and, hence, on the shale 'revolution'. This circumstance facilitates the historical investigation and its correlation with the E&P's dataset, focusing the analysis on the small independent company¹¹² and its history. Despite our focus on the period between 1993 and 1999, some previous efforts have consequences in this period's cost reduction. Thus, the next step overviews the previous Mitchell Energy efforts, leaving the investigation of 1993 to 1999 focused on HF adaptation to the next step.

Previous Mitchell Energy efforts to reduce its costs on the Barnett shale

Steward (2007) affirms that between 1980 to 1995, the company makes several incremental improvements to reduce the drilling time by more than 50%. From an average of 18-22 days to only 11 days, thus reducing the total cost to drill by 15%. The savings are mostly derived from the better specification of drilling mud, reduction of the circulation control, and better efficiency on the utilization of down-hole motors (Steward 2007, 108–10).

¹¹¹ Another two historical facts support the Mitchell leading role in Barnett. First, the company is responsible by the first well drilled in Barnett yet in 1981. Second, until 2001, from a total of 1 292 wells focusing on the Barnett shale, Mitchell Energy is responsible by 846, or 65% of the total (Steward 2007).

¹¹² The classification of small is relative and relies on the metric utilized. Comparing Mitchell Energy with the O&G majors, we can classify it as small. However, considering the typical natural gas companies at that time, the company was large. In this context, its classification as large independent *natural gas* company looks like to match more precisely (Wang and Krupnick 2013, 30; Kutchin 2001, 7–8; Gold 2015, 100). In this thesis, we compare the company with the major O&G, justifying the utilization of the term small independent company.

Another way that the company reduces its costs¹¹³ is through gains from the previously established infrastructure. The O&G's development on the Barnett region had started before the first operations with the shale formation. The entire infrastructure to proceed with the E&P's activities is already in place at the starting of the shale exploration, reducing the necessity of additional investments. On this topic, it is noteworthy the costs' reduction via two components. The first is the utilization of wells already drilled, and the second is the gas transport network (Anderson 2013, 118).

Previous O&G's activity in the region resulted in several wells drilled, focusing on deeper formations and an already constructed gas network infrastructure. After the depletion of the traditional resources, the productive wells were abandoned. Thus, the examination of another productive zone using the same well reduced the drilling costs. Additionally, these wells are also utilized as injection wells destined for both water and production residues disposal, reducing the production costs (Stevens 2010, 12; Wang and Krupnick 2013, 30).

Between 1981 and 1986, Mitchell Energy used wells already drilled to produce from shale, reducing their costs with possible failures. The available abandoned wells reduced expenses and investments to proceed with the E&P's activities providing valuable knowledge on the early stage of development in the region (Kutchin 2001, 20–21; Shellenberger 2011).

Considering the gas network, we emphasize that the Barnett region already had a gas pipeline network connecting the area with the consumer's market (IEA 2009, 415). This kind of infrastructure reduces the development costs associated with the necessary initial investment to transport the fuel.

Observing market risks for its output, two factors helped the company reduce them in Barnett shale's early exploratory phase. The first was the direct incentives to stimulate production from high-cost regions. The second was a contract to sell its output with higher prices than the obtained in the market¹¹⁴. Through the direct incentives, the company obtains both the

¹¹³ As previously defined, the costs terminology utilized on this thesis refers to the average costs by a unit of product, meaning that there are two possibilities to attain a cost reduction: an increase in output or, a reduction in inputs (Bohi 1998, 2; Iledare, Pulsipher, and Olatubi 2001). Independently of the roots, from the investors' point of view, an increase in output has the same effect of a reduction in the quantity of inputs necessary to extract the O&G, being both highly desirable and generating a reduction in costs.

¹¹⁴ While the contract is signed in 1954 it is finished after the natural gas oversupply at the end of 1980s. Through this contract with Natural Gas Pipeline, the company's output flows through an interstate pipeline with a guaranteed price. The contract was highly favorable for Mitchell Energy once the buyer paid an additional 1.25 dollar than the market price, giving additional price incentive to produce and also advancing cash to the company build reserves through drilling activities. Additionally, by the contract, Mitchell Energy establishes the basis to construct their first gas processing facility allowing the company

higher ceiling prices and the tax credit for their output. In July 1983, the company demanded FERC to classify the Barnett shale formation as a tight gas to access the higher price ceiling under Section 107(b) of the NGPA of 1978, being this demand is approved in late 1985. Finally, the company also benefits from the Section 29 of the Crude Oil Windfall Profit Tax Act of 1980, receiving the tax credit for the production that does not access the higher price ceiling guaranteed to the output from high cost unconventional reservoirs (Wang and Krupnick 2013, 25–26; Steward 2007, 50–54).

Considering the indirect incentives, Mitchell Energy benefited from US government programs support, sharing the costs with investments, and giving inputs to improve parallel technologies focusing on expanding HF technique efficiency. Among the company's benefits, its first horizontal well in 1991 was drilled, sharing costs with the GRI program. Additionally, during all the 1990s decade, after guarantee a large acreage position on Barnett shale, the company involved the GRI to access financial and technique assistance. Among the projects, GRI supports Mitchell Energy to drill infill wells to advance with the development of the microseismic fracture mapping technology¹¹⁵ (Wang and Krupnick 2013, 27–28; Steward 2007; Bowker 2007, 8).

2.4.3.3 The 1999's wells' productivity rise as a consequence of the improvements in the HF process

During the early exploratory operations¹¹⁶ in the Barnett shale, the HF technique is still being adapted to the unconventional shale reservoir environment. This adaptation is made through a successive trial-and-error approach to reduce the operational costs and keep the E&P activity in the region. In this context, the Mitchell Energy efforts focused on reducing the costs with both drilling and the HF process.

From these activities, HF is the most expensive being justified by both the high quantity of previous treatments with chemicals and its operation. In this case, the company focused on improving the HF process to reduce its costs. Early fracking operations are based on the

to extract from its output the richer fraction of natural gas, the condensate (Kutchin 2001, 20–21; Shellenberger 2011; Steward 2007, 26–27).

¹¹⁵ Differently of others seismic methods, this one is passive and consist to drill 'listening' wells near to the HF objective just to pick up the fracture's noise through seismic devices (geophones) triangulating this datum to map their evolution. This method allows to assess the success and orientation of the fractures created.

¹¹⁶ This term is used firstly by Middleton et al. (2017) referring to the period between 1993 and 1998, mainly given the existence of reliable and public official data given by RRC. However, we emphasize that the Barnett shale exploration begins in 1981 when Mitchell Energy drilled a well targeting this formation (Steward 2007).

knowledge obtained from HF on conventional reservoirs, thus demanding a mixture of gelled water, nitrogen, and high quantities of quality sand to fracture the rocks (Bowker 2007; Walker et al. 1998).

The component more expensive in HF operations was its fluid. Among the fluid components, its backbone is the proppant. The primary proppant function is to create and keep the reservoir's aperture during the production (Liang et al. 2016). According to Bowker (2007), a consensus before 2000 is that HF fluid has to maximize the reservoirs' aperture. The principle is simple and derived from the focus on the low reservoir permeability constraining natural gas flow. In this case, the HF approach applied to conventional reservoirs focuses on maximizing the reservoirs' aperture to improve its permeability, positively influencing the production flows. Finally, among the components of HF's fluid, the most expensive are both gel and sand. While the sand has the function to keep the reservoir's fractures open, acting as the proppant, the gel's role is to maximize the quantity of sand that the fluid can carry. Thus, according to the consensus, to maximize the reservoir's aperture and the production flow, the HF operation has to maximize the quantity of sand and, consequently, gel quantities (Bowker 2007).

In the Barnett' shale, Mitchell Energy re-thinks HF operation through several tests to reach savings in the 1990s, making an evolution on costs that allowed it to increase the drilling pace. During all the tests, the company analyzed its data to validate the operation basing its method on a trial-and-error approach (Wang and Krupnick 2013; Bowker 2007; Steward 2007; Gold 2015).

The first step is to test HF with lower sand quality, having a positive result. From this first encouraging result, the company keeps the tests with lower quantities of nitrogen. The result proved that a lower amount of nitrogen does not influence the wells' productivity, justifying their elimination of HF operation. With this second positive response, the tests encompass the pre-fracture acid treatment and, finally, HF's gel. All these components are reduced or eliminated from HF operation, reducing their costs by more than 50% (Wang and Krupnick 2013, 20–23; Bowker 2007; Steward 2007, 110–12).

Finally, an engineer involved in the Mitchell Energy HF operations suggests introducing a new method replacing the gel with fresh water¹¹⁷. By this approach, HF solution reduces the

¹¹⁷ Three different sources affirmed that the engineer Nick Steinsberger was the responsible by the introduction of the slick water fracture method indicating that this approach is based on the positive results firstly obtained on the UPR fields on sandstones tight reservoirs in East Texas (Steward 2007, 112–13; Gold 2015, 126–28; Zuckerman 2013, 77–78).

necessity of proppant (sand), also reducing the quantity of gel, forming a fluid based on water, and carrying low amounts of sand. This solution is named slick water fracture (SWF), basing a new HF method named light sand fracture (LSF). Despite the utilization of this method on sandstones tight reservoirs in the Cotton Valley in East Texas by the UPR company (merged with Anadarko in the end of the 2000s), there are not a full understanding of why this new approach works on tight reservoirs and even how it could react on shale reservoirs¹¹⁸ (Gold 2015, 126–28; Zuckerman 2013, 77–78; Walker et al. 1998; Steward 2007, 112–13). Notwithstanding, as this new HF fluid does not damage the shale reservoirs and reduces the costs with the expensive HF gel, the company proceeds with the experiments in 1997 through three wells. The initial tests with the SWF method were trick and inconclusive¹¹⁹ (Steward 2007, 110–14; Gold 2015; Zuckerman 2013).

In light of the unsatisfying results with the SWF method on the Barnett shale, the company proceeds with additional tests utilizing the same approach on three wells in 1998. The experiments targeted to delimit and better understand the volatile results obtained by utilizing the SWF in 1997. The first drilling had a disappointing result while the second drilling, the S.H. Estate Griffin 4, completely change the perspectives. It started the production at a rate of 27 kcm/d increasing to achieve the peak of 34.9 kcm/d in October 1998 and an average of 25.2 kcm/d during the first 6 months. Comparing with their peers drilled at the same year, the well performed very well, presenting a higher initial flow than the average of 24 kcm/d and a six months' production average superior to the average of 17.7 kcm/d (Steward 2007, 110–14; RRC 2019; Middleton et al. 2017; Gold 2015, 117–35).

Despite the positive results with the S.H. Estate Griffin 4 utilizing the SWF, there is not a full comprehension of why the SWF approach obtains higher levels of natural gas flows than HF's gel in shale reservoirs (Gold 2015, 135; Zuckerman 2013; Steward 2007; Walker et al. 1998). In

¹¹⁸ While, on average, the East Texas sandstones has a porosity of 0.0001 darcy, the Barnett shale has even lower porosity, arriving on average to 0.0000001 darcy (Gold 2015, 128).

¹¹⁹ The first well, W. A. Askey B-4 starts its production in June 1997 at an impressive rate of 7.4 kcm/d, quickly increasing to achieve 28.97 kcm/d in July and the average of 20 kcm/d at the end of the year. The second well, W. D. Johnston B-14 starts its production in August 1997 with an initial rate of 9.31 kcm/d increasing to achieve 15 kcm/d in October and the average of 10.7 kcm/d at the end of the year. Finally, the third well, Bryan D-3 starts its production in July at a very poor rate of 0.25 kcm/d, being refracted with HF gel later in the same year to compare the results. Comparing these data with the first-month production of the wells drilled in 1997, their results are worst than the average of 30 kcm/d. However, observing the average productivity considering the first 6 production months, the wells drilled in 1997 achieves the value of 19.3 kcm/d, representing a good result from the first well, W. A. Askey B-4 and an under the average for the second well, W. D. Johnston B-14. The third well was a disappointment (Steward 2007, 110–14; RRC 2019; Gold 2015; Zuckerman 2013).

this context, Mitchell Energy dedicates their E&P efforts to collect more data, engaging their staff to interpret and delimit the differences in the natural gas flow to elucidate the interaction between an HF utilizing the SWF approach on shale reservoirs. To reduce the costs with this massive experiment, the company decides to test the SWF approach on old wells with small natural gas flows, selecting those wells starting the production in 1994 or even older. In these wells, the company proceeds the HF utilizing the SWF, beginning the process in the final months of 1999 (Steward 2007, 127–29). The introduction of the SWF approach associated with an HF procedure in these wells is the key responsible for the productivity increment in the wells drilled in 1994, as previously revealed by Figure 17.

According to Bowker (2007), this small variation on HF fluid utilizing the SWF approach confronts the usual HF approach. Further studies demonstrate that, on tight reservoirs as the shale one, the fracture aperture is less relevant than their network size, demanding a different objective. While in conventional reservoirs, the maximization of the aperture is essential to maximize the flow, on tight unconventional reservoirs, the connection with natural fractures has been presenting better flow results than the traditional vision aiming to optimize the fractures apertures. In other terms, instead of augmenting the reservoirs' permeability keeping their aperture, on shale reservoirs, HF's objective is to maximize the fracture's network connecting the reservoir's natural fractures (Bowker 2007). Once the objective with the HF operation on the Barnett shale reservoirs changed, its fluid also changed, resulting in lower costs to HF the reservoirs. Instead of maximizing the quantity of sand intensifying the amount of gel on the fluid, the SWF approach is based on a high water quantity with a small amount of sand (Steward 2007, 110–14; Harper 2008; Karra et al. 2015).

To conclude, between 1993 and 1999, the increase in the regional output is based on expanding active wells with volatile productivity, demonstrating the uncertain results from the HF process on shale, and the insufficient degree of knowledge about this technique. Additionally, we can assume that the critical force supporting the constant increase in the number of wells and experiments on the Barnett shale is a permanent reduction in costs attained through an operational optimization associated with a stable natural gas price. The conjugation of direct and indirect benefits and several improvements reducing the development costs on the Barnett shale explains the continuous increase in the number of active wells, resulting in increments on the set of regional knowledge through experiments and information. The accumulation of knowledge successfully nourished a learning curve through the trial-and-error approach, demonstrating the superiority of the SWF method to conduct the HF operation. The SWF's adoption in the HF process represented a breakthrough since it conjugates a

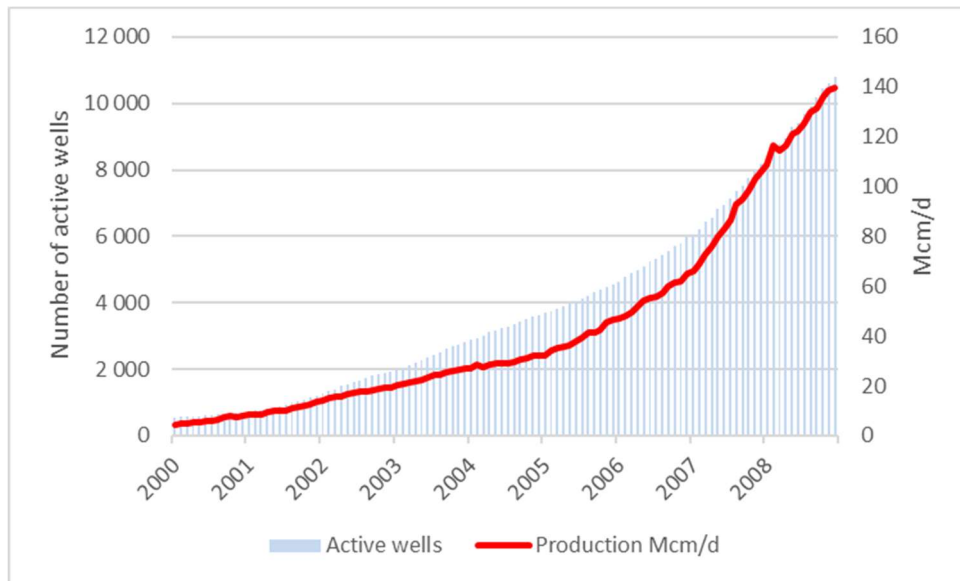
permanent cost reduction saving by eliminating the expensive HF's gel with an increase in the production rates. In the context of stable prices, the cost reduction supports the increment on E&P activities, augmenting the natural gas flows obtained through the HF process on vertical wells.

2.4.4 The second Barnett learning curve's phase: the increasing quantity of operators focused on augmenting the reservoir's recoverability through horizontal drilling

Unlike the first learning curve stage, there is a substantial increment in prices in the second stage between 2000 and 2008. It influences the E&P activities and the adoption of technologies to raise the recoverability factor, notably through horizontal drilling. In this context, both E&P indicators production and active wells, augment. Additionally, there is an expansion in the number of operators conjugated with a decreasing production share of the leading company. These data's association reveals a movement to catch-up the leader company and mastery of the shale extraction technologies, representing a positive spillover from technological breakthrough.

Figure 18, illustrates the evolution of the active wells through columns (left axis) and the production through a red line (right axis) on the Barnett shale between 2000 and 2008.

Figure 18. Number of active wells and the production on the Barnett shale region between 2000 and 2008 by month



Source: Based on RRC (2019) and Middleton *et al.* (2017).

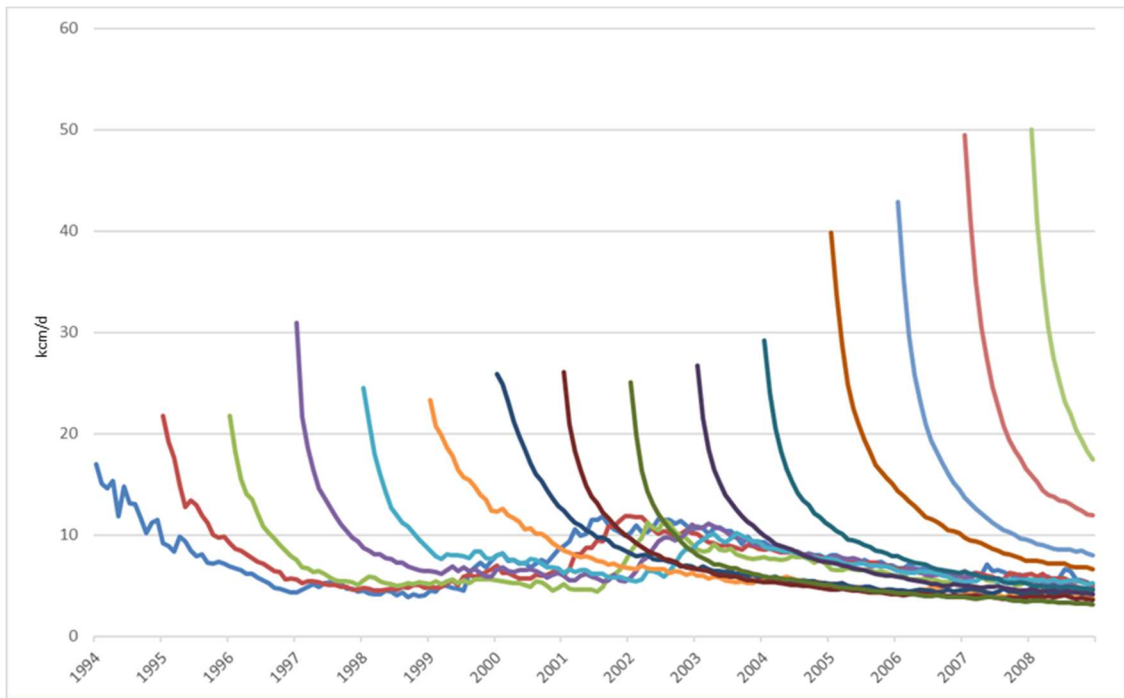
The production increases according to the number of active wells, starting 2000 at 4.3 Mcm/d level and almost achieving 140 Mcm/d at the final of 2008. Simultaneously, the active wells augment its pace, starting 2000 at 542 and reaching 10 785 in December 2008.

Scrutinizing the number of active wells, the most remarkable behavior is the increasing pace this metric achieves. Initially, during the 2000 year, there is a net addition of 200 wells, increasing in the subsequent year to 500 and almost 800 during 2002. At the beginning of 2003, the total active wells in the region overcome 2 000. The addition of new wells keeps mounting, reaching almost 1 000 new active wells during 2005, overcoming the addition of 2 000 new active wells in 2007. Finally, the total active wells overcome the 8 000 level in 2007, reaching 10 000 in 2008.

Following the addition of wells, the total production in the region also continuously increased its pace. It achieves the 10 Mcm/d level during 2001 and overcomes 20 Mcm/d at the beginning of 2003. In 2005 it exceeded the 40 Mcm/d level and the 80 Mcm/d level in 2007, finishing the 2008 year close to 140 Mcm/d.

In summary, this period is based on an expansion of the E&P's activities, in line with the expansion of the number of active wells in the region. To investigate the wells' productivity gain, we dedicate the Figure 19, below, to illustrate the average production of new wells splitting the data by the year that the well was drilled between 1994 and 2008.

Figure 19 – Average production of new wells by year of drilling between 1994 and 2008



Source: Based on RRC (2019) and Middleton *et al.* (2017).

Observing the figure after 2000, our period of interest, there are two interesting movements in the new wells to assess. Between 2000 and 2004, the first is of relative stability on the initial new wells' productivity below the value of 30 kcm/d. After 2004 until 2008, the second is characterized by increasing productivity when new wells overcome the barrier of 30 kcm/d in 2005 and the 40 kcm/d in 2006, overlapping the 50 kcm/d in 2008. The following section examines in more detail these movements.

2.4.4.1 The application of the SWF in the old wells positively influencing the wells' productivity between 2000 and 2002

The dissemination of the SWF on old wells as a mechanism to validate their achievements and propel their recoverability is the critical determinant of the increasing wells' productivity starting in the final months of 1999 lasting until 2002. In this period, the wells' productivity rises almost two times, from a previous level of around 6 kcm/d in 1999 to values close to 11 kcm/d in 2002 as showed by Figure 17.

Inspecting the average wells' productivity from old wells between 2000 and 2008, there is an increase in the productivity from wells drilled between 1994 and 1998. The productivity gain on wells drilled during 1994 starts smooth at the beginning of 2000 but quickly intensify the gains during 2001. These wells drilled in 1994 have an average production close to 4 kcm/d in

1998, quickly increasing until achieving a value of 11.5 kcm/d in 2001. Similar behavior happens on wells drilled in 1995, with a continuous increase in the average production presenting a major surge in 2001.

The wells drilled between 1996 and 1998 present similar productivity behavior. Thus, we conclude in HF old wells utilizing the SWF approach increases their pace since 2000. However, after 2002, the diminishing quantity of available wells to operate an HF utilizing the SWF approach limits additional wells' productivity gains, gradually reducing it.

Finally, we highlight that the influence of the SWF approach in the average production of new wells is marginal. However, it has a relevant effect on costs, making the HF operations less costly, reducing the E&P risks associated with the exploitation of this frontier zone.

2.4.4.2 The decline in the wells' productivity between 2002 and 2004 as a consequence of three factors

Between 2002 and 2004, the wells' productivity falls from its previous level of 11 kcm/d to values close to 9 kcm/d as a consequence of three factors associated. First, a small growth in the average production from new wells. Second, the end of the rebound in the productivity of the old well given by HF works utilizing the SWF approach. Third, the growing quantity of players in the Barnett shale to capture the spillovers of the increasing production in Mitchell's area.

Observing only the wells' productivity of new wells, between 2002 and 2004, the 12 months average production increases from 13.2 kcm/d in 2002 to 16.6 kcm/d in 2004. From the examination of the average production obtained in the first month, it increases from 25 kcm/d in 2002 to 29.2 kcm/d in 2004 (RRC 2019; Middleton et al. 2017). Thus, the increase in production from new wells is insufficient to offset the decline in production from legacy wells¹²⁰, reducing the wells' productivity. Observing the average legacy production, it falls from 8.6 kcm/d in 2002 to 7 kcm/d in 2004. Considering just the SWF's influence on wells drilled between 1994 and 1998, the average legacy production falls from 9.4 kcm/d in 2002 to 8.1 kcm/d in 2004 (RRC 2019).

The last factor is the escalation in the number of operators and the gradual fall on the production leader's share of the total natural gas. Considering the existence of a learning curve, we assume that the leading company already achieved a productivity differential through its

¹²⁰ We applied the terminology adopted by EIA (2020a) in its Drilling Productivity Report of legacy production meaning "(...) estimates of total oil and gas production changes from all the wells other than the new wells." (EIA 2020a)

learning process. Thus, any new player has to learn from the previous process, demanding its adaptation and the beginning of the catch-up process. In these circumstances, the falling leading share associated with the introduction of new players in the region could reduce the wells' productivity because of the gradual catching-up process. The catching-up process occurs when new players focus on reaching the leader's productivity, demanding the internalization of the knowledge through E&P activities. At the initial stages of the catching-up process, we expect a reduction in the regional average given the gradual knowledge internalization concerning the new companies. We dedicate Table 7, below, to show the evolution of this element in the region.

Table 7 - Quantity of active operators and the leader's share in the total Barnett shale production between 2000 and 2008

Year	Quantity of Active Operators	Leader's Share
2000	18	81.44%
2001	35	78.07%
2002	58	70.94%
2003	76	64.87%
2004	95	54.40%
2005	125	41.03%
2006	139	33.74%
2007	154	30.47%
2008	158	27.49%

Source: Based on RRC (2019).

Table 7 reveals a continuous evolution of the operator's quantity associated with a fall in the leader's share. In 2000, there are only 18 different operators in the region, rising to 35 in 2001, 58 in 2002, 76 in 2003, and achieving 95 in 2004. A substantial increase considering that until 2001, there were only 51 different operators in the same region. Finally, the leader's share presents a decline in 4 years, falling from 81.44% in 2000 to 54.4% in 2004 (RRC 2019).

Observing the quantity of new active wells in the region, in January 2000, there are only 542 wells, increasing to 705 in December and 1 200 at the end of 2001. Between 2002 and 2004, there is an addition of nearly a thousand active wells each year (RRC 2019).

The increasing number of new wells and operators in the region demonstrates the growing incentives to catch-up technological advancement generated inside the leading company, Mitchell Energy. About this theme, we emphasize three main facts. First, Devon Energy acquires Mitchell Energy in 2002, an operation focusing on double objectives. Internalize the HF knowledge based on the SWF approach in the Barnett shale context and obtain additional acreage to increase further the production (Gold 2015; Steward 2007; Zuckerman 2013). It is

noteworthy that Devon could be classified as a major independent company, being the first to access the information about technological adaptation obtains in the leading company through this acquisition.

Second, in 2003, the EOG company starts its production in the area. In the first year, the company reaches a modest fraction of 0.02% of the whole Barnett production. Notwithstanding, the company progressively mount its output until it reaches 13.3% in 2008 (RRC 2019).

Third, in 2004, two more relevant shale development players began their operations in the Barnett shale, XTO, and Chesapeake. Similarly to the EOG case, these players continuously increase their production share in the area reaching in 2008 15% and 16.4%, respectively (RRC 2019). Finally, we emphasize that the four companies, Devon, EOG, XTO, and Chesapeake, are the key players managing the widespread of the shale 'revolution' to other US shale regions (Gold 2015; Zuckerman 2013).

Thus, we conclude in the increasing competition by acreage in the Barnett shale reveals major independent companies' concerns to catch-up with the accumulated knowledge from the leader. In this context, the rise in the E&P's investments represents the initial positive spillovers from the first increase in the wells' productivity obtained from the introduction of the SWF approach in the Barnett shale¹²¹. Simultaneously, as the catch up is a progressive process, we also assume that at the beginning of it, the new companies entering in an area could present a wells' productivity lower than the leader one, reducing the total wells' productivity.

To conclude, the association of these three factors between 2002 and 2004, the small increase in the new wells' production, the end of the SWF production rebound on old wells, and the surging competition are the primary determinant of the reduction in the wells' productivity.

2.4.4.3 The adaptation of horizontal drilling in the Barnett shale as the critical cause of the wells' productivity surge after 2005

The last wells' productivity movement is connected with a substantial increase in prices. The price's increase encourages the operators to increment the E&P's activities in the Barnett shale region. In this context, the leading company, Devon, introduces in the shale reservoirs the horizontal drilling. This technological adaptation in the Barnett shale environment targets to raise the drainage area augmenting the wells' productivity.

¹²¹ Middleton *et al.* (2017) named the association of the first movement of productivity gain and the second movement representing a productivity fall as technical success experience in the Barnett' shale region (period 1999-2004).

Compared with the vertical wells, the horizontal ones are more complex and expensive. In this circumstance, the introduction of this techniques in the shale's exploitation is based on two factors. First, the fast increase in natural gas prices, stimulating any operator to increment natural gas production through techniques raising the recoverability factor. Since 2000, natural gas prices have been presenting a rising movement, as previously described in section 2.4.2.1. On nominal terms, between 2000 and 2004, the natural gas price grows from US\$ 3.5 MBtu to US\$ 5.3 MBtu, representing an accumulate increase of 48.4% or, on average, 10.4% per year. Second, the merger between Mitchel and Devon.

Vertical wells expose a determined area allowing the pressure differential conjugated with the reservoir's permoporosity to naturally expel O&G¹²². Tight reservoirs, as the shale case, reduce the wells' ray, demanding any other action to aid the ejection of the reservoir's fluids, as the HF technique. In these circumstances, horizontal wells ensure a higher reservoirs' exposure than vertical ones, being adopted to improve the recoverability factor through a better drainage area (NPC 2011; Walker et al. 1998; Bowker 2007). According to this fact, GWPC estimates that six to eight horizontal wells can access the same well drainage area as sixteen vertical wells (GWPC 2009). To conclude, despite the higher costs to drill horizontal wells instead of vertical ones, the higher reservoirs' exposition and its favorable influences in the O&G recoverability factor may justify this higher investment.

However, the initial results of the adaptation of horizontal drillings on the Barnett shale region were discouraging. Mitchell Energy drilled its first horizontal well in the Barnett shale with GRI's technical and financial assistance in 1991 with a great disappointment. The company also tried another two horizontal wells in 1998 and 1999, however obtaining a similar discouraging outcome. The last attempt was made in 2000 with another frustration provided by mechanical problems, resulting in a total cost of half a million dollars (Wang and Krupnick 2013, 27–28; Steward 2007, 182). In the company's view, the accumulation of fails with horizontal wells demonstrates that shale exploitation should not be based on horizontal wells (Steward 2007, 182).

After Devon's acquisition in 2002, there is a change in the leader's perspective around horizontal drilling in the Barnett shale development. Contrary to Mitchell Energy, Devon had

¹²² The Darcy's law defines the production' flow from three main elements linked with the O&G's quality and the reservoirs quality. From the reservoirs, its permoporosity and pressure influence the production flow. From the fluid, its viscosity is the key element. In these terms, the wells' drainage area is limited by the capacity of the fluid to move inside the reservoirs, given by its viscosity and, the reservoirs permoporosity associated with its pressure.

several economic successes with horizontal wells, approving another five attempts with this area's extractive method. Another distinction is the company emphasis to add parallel techniques during the tests. In this case, Devon approved the test associating horizontal drilling with the microseismic mapping and the 3-D seismic dataset. While the first provides relevant information to delimit the HF propagation, the second is useful to navigate the horizontal part of the well, focusing on optimizing the reservoir's drainage area. At this time, the wells outperformed any previous experience¹²³, boosting the company to file a demand to drill more 80 horizontal wells in 2003 (Wang and Krupnick 2013, 27–28; Steward 2007, 182; Shellenberger 2011).

When this demand becomes public, 25 other companies require authorization to drill 100 horizontal wells. The macro data from Barnett shale shows the acceleration in horizontal drilling adoption. All companies operating in the Barnett shale drilled 75 horizontal wells in 2003. The results from the utilization of horizontal wells are positive, mainly based on the Devon Energy wells. In this case, the company reliance on 3-D seismic data to navigate the horizontal well shows better outcomes than their peers¹²⁴. These positive results stimulate even more investment and acquisition of regional 3-D seismic data associated with drilling additional wells to continue with the microseismic mapping to monitor the fractures expansion in horizontal wells. The association of all these technologies in the Barnett shale's exploitation makes the wells' productivity substantially increases between 2005 and 2008, coinciding with horizontal drilling expansion and an increasing recoverability factor.

In 2005 the horizontal wells were more than double of the vertical ones, and in 2009, less than 6% of all new wells in this region are vertical (Wang and Krupnick 2013, 27–28; Steward 2007, 182; Shellenberger 2011). Observing the wells' productivity, from a level close to 9 kcm/d in 2005, it increases continuously until a peak of 13 kcm/d in 2008. The major factor sustaining this wells' productivity increase is the average production from new wells. From a previous level

¹²³ Three wells were placed on low geological risks areas and two on high ones. The initial productivity is higher when compared with the vertical wells. The first three wells produced 3.5 times more than vertical wells and the other two high-risk produced 2.5 and 3.3 times more than the vertical wells (Wang and Krupnick 2013, 27–28).

¹²⁴ To correct plan and direct horizontal wells by productive zones of the deposits, geological knowledge is essential. From all companies in the Barnett shale, before 2003 only Devon Energy has this essential information about the 3-D seismic data, justifying the productivity difference between their wells and the other companies wells (Wang and Krupnick 2013, 28; Steward 2007, 183). Notwithstanding, analyzing the wells' productivity differences between Devon's wells and other companies, Republic Energy viewed the relevance of this kind of data to place and direct horizontal wells in 2003, sharing this information with others operators. After this 'revelation', the productivity differences of the horizontal wells between companies in Barnett shale wells become insignificant (Steward 2007, 183).

of 29.2 kcm/d in 2004, it rises to 39.7 kcm/d in 2005, 42.8 kcm/d in 2006, 49.4 kcm/d in 2007 and almost 50 kcm/d in 2008. In proportional terms, the average production from new wells almost doubles, accumulating growth of 70.9%. These encouraging results from the horizontal drilling adaptation utilizing the SWF approach and the useful information from the 3-D seismic and microseismic mapping consolidate the exploitation approach in unconventional shale reservoirs.

Overcoming the frontier zone through the expansion of the E&P's activities in the Barnett shale: the outbreak of the shale 'revolution'

While Devon and other operators demonstrate a progressive increment in production from new wells revealing the whole Barnett shale potential, the growing natural gas price enhances the interest of outsiders O&G companies in these achievements. The quantity of different operators and the leader share summarizes the ever-increasing interest in this region. The number of operators in the region keeps rising from 95 in 2004 to 125 in 2005, 139 in 2006, 154 in 2007, and 158 in 2008. Concomitantly, the leader's share continuously falls, initially at a small pace from 81% to 70% between 2000 and 2002 but then increasing its pace and achieving merely 27% in 2008.

Although the uncertainty about the O&G *in-place* volumes in the Barnett shale unconventional reservoirs, the increasing wells' productivity associated with the accumulated production reveals a net growth in the recoverability factor. The set of techniques summarized by the utilization of HF associated with horizontal drilling increased the shale reservoirs' recoverability factor enabling the extraction of substantial volumes of these O&G's resources. Thus, in this final phase of the learning curve, other companies benefit from the accumulated knowledge capturing the positive spillovers from the previous efforts.

Additionally to the surge in the recoverability factor, the E&P activities increase their pace. The most representative data of this boom is the active wells. From a previous quantity of 3 680 wells in January 2005, this indicator grows continuously, overcoming the 10 000 wells level in September 2008¹²⁵ (RRC 2019).

The increasing production associated with the expansion of the E&P's activities in the region between 2005 and 2009 represents the positive results of two determinants. First, the increase in the recoverability factor from unconventional shale reservoirs through the association of both horizontal wells and HF. Second, the movement to catch-up the leader

¹²⁵ Analyzing the same movement, Middleton *et al.* (2017) named this third movement by high-volume production (2005-2014).

represented by the several different operators mastering the technologies to exploit unconventional shale reservoirs.

To conclude, the second learning curve is characterized by three major determinants: the consolidation of the SWF approach as a technological achievement that reduces the HF operation's costs; the adaptation of horizontal drilling to the shale exploitation associated with others technologies; and, the widespread of both technologies to other companies demonstrated through the leading's share shrinking.

2.5 Chapter Conclusion

Several authors have supported that the determinants of unconventional shale reservoirs development in the US case are based on two main elements. First, a particular US institutional environment shapes the relationship between the government and the private sector. Second, a learning curve that gradually overcomes the technological challenges represented by the necessity to improve the reservoir's recoverability (Wang and Krupnick 2013; Binnion 2012; Middleton et al. 2017; Kim and Lee 2017; Fukui et al. 2017). The association of these elements allows for increase production from unconventional shale reservoir, transforming unconventional reservoirs frontier zones' commercial attractiveness, and resulting in a 'revolution'.

In this context, this chapter examines the specific US context relating to unconventional reservoirs' development. This investigation aimed to shed light on the determinants of the frontier zone development, examining the instruments and mechanisms associated with the context of their implementation, and delineating the essential variables to proceed with a comparison and analytical contrast with the Argentinean case. To provide an analysis of the instruments and mechanisms mitigating both types of risk (technological and economic), this thesis structured an analytical framework based on historical institutionalism and the evolutionary theory, summarized in Figure 5.

On the one hand, the historical institutionalist approach allows this thesis to examine institutional change through a long historical process. From the previous country's context revealing an intricate regulatory framework generating market imbalances, our analysis of the reform's sequence reveals a trajectory leading to market liberalization. This market liberalization allowed the dynamics between supply and demand to be reflected through the equilibrium prices, resulting in an increase in natural gas prices before the shale 'revolution' took place. Despite that the price increases did not pointedly target the development of unconventional reservoirs, they mitigated economic risks associated with these novel extractive techniques.

Additionally, we emphasize other government efforts that resulted in the mobilization of tax subsidies (lasting until 2002) and in higher natural gas prices (under the price controls period) to accelerate the exploitation of high-cost zones. Both elements, institutional reorganization and financial support, determined the instruments implemented by the US government, mitigating economic risks of frontier zones.

On the other hand, the evolutionary theory provides the theoretical support to analyze the complex process of introducing technological progress. This literature assumes that the process of technological change is endogenous, originating within the capitalist system, and generating qualitative transformation in society, chiefly in the economy. Thus, the evolutionary literature provides the theoretical support to identify relevant elements concerning this multifaceted process of introducing technological change. Based on this literature, this thesis identified two main aspects to investigate. First, the actuation of focusing forces driving the acceleration of the technological trajectory. Second, the mobilization of some mechanisms that mitigate the technological risks characterizing frontier zones.

Concerning the focusing forces, this thesis accords with Rosenberg (1976) that prices (in this analysis, natural gas prices) are fundamental to impulse technological development. However, they are insufficient to provide a complete explanation, chiefly concerning the advance's sequence and timing. In this context, two elements are emphasized as relevant focusing forces directing and accelerating technological development: problems with supply (Rosenberg 1976); and the state role (Dosi and Nelson 2013; Dosi 1982). Thus, this thesis is concentrated on the country context regarding natural gas supply (such as shortages or other limitations), and the subsequent government reaction.

This particular attention allows this thesis to identify two main government efforts to accelerate technological advancement. First, through direct action, the government delimits the unconventional reservoir's potential, identifying additional national energy sources after the first oil shock and the natural gas shortages. Second, associated with the private sector, the government defines the technological trajectory relating to the adaptation of both extractive methods, HF and horizontal drilling, in order to unlock natural gas from unconventional reservoirs. In this particular case, the government provided financial aid for tests concerning HF and horizontal drilling on unconventional reservoirs, debating with private actors the techniques needed to proceed with technological adaptation.

Concerning the instruments and mechanisms used to mitigate technological risks related to the acceleration of its development, this thesis identified three: cooperation between public

and private sectors; the learning curve; and, the company's risk aversion. Our analysis demonstrates that the cooperation between public and private sectors aimed to accelerate the technological progress mitigating the technological risks. To attain this objective, the government creates bridging institutions and provided additional resources for basic and applied R&D.

The analysis of both the learning curve and the companies' risk aversion demands an additional delimitation for an in-depth analysis. To investigate these mechanisms considering the specific environment and actors, this thesis examined the first region to attain commercial production from unconventional shale reservoirs, delimitating the Barnett shale region as the center of our case study. Additionally, the learning curve incorporates diverse elements such as the heuristic of research, the knowledge cumulateness, R&D efforts, and the multifaceted feedback between firms and markets. Therefore, this thesis investigates the relevant periods (defined by the wells' productivity peaks) in order to focus our analysis on them. This thesis identifies two learning curve stages with different features that stem from the association between the wells' productivity peaks and the natural gas price movements.

The first stage is associated with a leading role played by Mitchell Energy, an independent natural gas company. The company focuses on reducing costs and accumulating knowledge (formed by experiences and information), mainly based on a trial-and-error strategy. These E&P activities aimed to introduce and test different HF methods, resulting in the SWF approach. The second stage involves other companies trying to catch-up with the leader's achievements. In the context of increasing natural gas prices, the objective changed from reducing costs to increasing the reservoirs' recoverability. Thus, the leading company (Devon Energy, which merged with Mitchell Energy) introduces horizontal drilling, associating this technique with seismic data to steer the well in the horizontal phase. Although both stages expand the regional knowledge available, the positive spillovers are perceptible during the second stage, represented by the increase production of other companies and, subsequently, embodied by the widespread of technological mastery to other shale regions.

Finally, we emphasize that unconventional reservoirs' heterogeneity obligates the adaptation of HF and horizontal wells to local geological contexts. Nevertheless, geological heterogeneity is not an obstacle to extraction from unconventional shale reservoirs. Considering the US example (i.e., *ceteris paribus* the institutional environment), different Basins and regions successfully managed to enable profitable production from unconventional reservoirs.

Chapter 3. The Argentinean frontier zone of Vaca Muerta

Argentina is the second country in the world to experience a significant increase in natural gas production from unconventional shale reservoirs. The country's unconventional reservoirs extractions, including from shale and tight sources, increased substantially over a 10 years' period, from 2.8 million cubic meters per day (Mcm/d) in 2009 to 57.7 Mcm/d in 2019. The production from the *Vaca Muerta* region located in Argentina's Neuquén Basin are the main source of this impressive growth; increasing its participation in Argentina's natural gas production from 2% in 2009 to 40.3% in 2019. Additionally, in 2019, the *Vaca Muerta* region represented almost 95% of the output from unconventional reservoirs in Argentina (Secretaría de Energía 2020b). Due to the increasing production from unconventional reservoirs, Argentina joined the LNG exporters with a nominal capacity of 1.9 Mcm/d in 2019¹²⁶ (GIIGNL 2020, 38).

According to an IEA (2013) study, Argentina hosts the second-largest O&G resources of unconventional reservoirs globally, most of which are concentrated in the *Vaca Muerta* region (EIA 2013). Different from the Barnett shale case based exclusively on shale reservoirs, the Argentinean unconventional reservoirs in *Vaca Muerta* comprise both tight and shale¹²⁷. In these circumstances, the *Vaca Muerta* region allows investors to implement technological adaptations in unconventional tight reservoirs through vertical wells, which are notably less expensive than horizontal wells.

Our analytical framework associated with our previous study of the United States (US) case leads us to examine the Argentinean case based on the instruments and mechanisms mitigating the frontier zones' specific risks. We highlight that this analysis also considers the particular country's context, prompting us to describe the Argentinean particularities and ponder their influences on the instruments dealing with frontier zones' features. Consequently, this chapter has two objectives.

The first goal is to analyze, for the Argentinean case, the implementation of the instruments and the actuation of mechanisms that handle with the economic and technological risks inherent to frontier zones. This analysis is based on our analytical framework defined in chapter 2, summarized in Figure 5.

¹²⁶ The original data are in million tons per annum (MTPA), achieving the value of 0.5 MTPA.

¹²⁷ Both reservoirs, tight and shale are incorporated in unconventional category. Nonetheless, the tight reservoirs have higher levels of permeability and porosity when compared with shale reservoirs.

Second, this chapter aims to compare the Argentinean experience with that of the US, taking into account each country's specificities and incorporating each specific context. This comparison allows this thesis to contrast the instruments and mechanisms of actuation in each case, qualifying them through different implementation contexts.

Similarly to the US case, the main challenge of exploiting unconventional reservoirs in Argentina is reducing production costs. Compared with conventional reservoirs, the necessity of fracturing unconventional reservoirs increases costs and risks, limiting E&P activities linked with the technological adaptation used and, consequently, the learning curve associated with these activities.

In these conditions, the Argentinean government utilized similar instruments compared with the US to lessen technological and economic risks in its unconventional reservoir frontier zone. The economic risk is mitigated through two instruments previously described in our analytical framework. First, reorganizing its regulatory framework, which shapes a trajectory leading to a liberalization in price formation (nonetheless, until 2020, this process in incomplete).

Second, the increase in national natural gas production. Since 2008, the Argentinean government has been guaranteeing a minimum wellhead natural gas price at higher levels than the market prices. From the investor's perspective, the minimum price is a financial support to E&P activities. Like in the US case, initially these higher wellhead natural gas prices do not aim, specifically, to accelerate unconventional reservoirs' development. Nonetheless, they provide the necessary stimulus for the development. In the Argentinean case, due to the positive results from unconventional reservoirs, the government redesigned the minimum price to encourage E&P activities only in unconventional shale reservoirs, recognizing the zone's potential and aiming to reduce economic risks of exploiting these resources. Finally, considering both cases, this thesis concludes in a higher susceptible to prices of E&P activities focused on exploiting unconventional reservoirs.

In both cases, Argentina and the US, the technological risk is mitigated by accelerating technological adaptation, including HF and horizontal drilling. Governments cooperate with the private sector to mitigate the technological risk associated with technical adaptation. Unlike in the US, in Argentina this cooperation is based on sharing the development costs with private companies, mainly international oil companies, with the national oil company. In this point, we emphasize that Argentina benefits from the previous technological development made in the US, which facilitates the technological adaptation in *Vaca Muerta*. Instead of testing several

kinds of technologies as in the US case, Argentina has only to adapt them to the local geological context.

An analysis of the learning curve in Argentina also found two learning curve stages. In both cases, the first stage is distinguished by an independent company that leads the process of adapting HF in unconventional reservoirs. The second stage corresponds to the association between HF and horizontal drilling, focusing on increasing the reservoirs' recoverability. At this stage, a new company merged with the previous leader. However, while in the US a bigger independent company merged with the leader, in Argentina, the national oil company incorporated the leading company. Additionally, in the Argentinean case, the leadership is more fragile, being split by two companies in the first learning curve stage and quickly contested in the second one. This dynamic demonstrates that the leadership in the Argentinean case is more fragile than in the US case.

Observing both stages, a remarkable difference is found in companies actuating for developing unconventional reservoirs. The Barnett case is predominantly independent private companies that are notably less risk averse. In contrast, in *Vaca Muerta*, the firms willing to endure these risks comprise a mix of public and private companies (including independent and international oil companies).

Another remarkable difference from the US case is that, for *Vaca Muerta*, the learning curve stages are divided by reservoirs (tight and shale), while there are only shale reservoirs in the Barnett region. This characteristic of *Vaca Muerta* allows producers to engage in the first learning curve stage, reducing costs through the utilization of vertical wells and achieving higher wells' productivity in tight reservoirs instead in the shale ones (that demand the association between HF and horizontal wells).

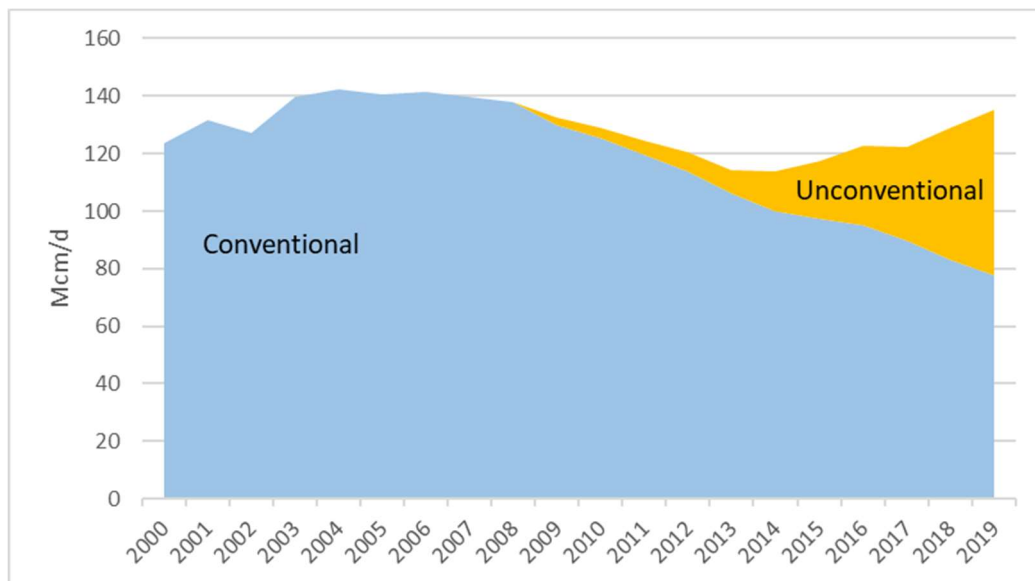
Finally, we highlight that the learning curve stages in both countries correspond to the Dosi's (1982) description. While the first stage corresponds to the emergence phase, the second corresponds to the industry maturity phase. Additionally, the first phase concerning the introduction of the technological advancement is characterized by a leading company while the second phase corresponds to increasing competition among firms seeking to catch up to the leader's achievements. It is interesting to observe that, in both cases, independent companies, notably the less risk averse, lead the process of introducing the technological advancement, demonstrating the relevance of these companies to the technological adaptation of unconventional reservoirs.

The following chapter offers more detail about the Argentinean case and is divided in three sections. The first describes the Argentinean context revealing the increasing natural gas output as a consequence of the growing production from unconventional reservoirs. The second examines the government instruments mitigating technological and economic risks. The third evaluates the mechanisms mitigating the technological risks encompassing the regional learning curve for unconventional reservoirs in the *Vaca Muerta* region and the market structure.

3.1 The scale of unconventional production and the Argentinean context

Similarly to the US case, the exploitation of unconventional reservoirs is the main cause for the rebound in Argentina’s natural gas production. While in the US, the production from unconventional shale reservoirs accelerates in the 1990s, resulting in the shale ‘revolution’ in 2005, in Argentina, unconventional reservoir extraction accelerates in 2014, serving as the leading cause of the national production increase. Figure 20, below, shows the evolution of natural gas gross production according to reservoir source (conventional and unconventional) between 2000 and 2019.

Figure 20 – Argentina’s natural gas gross production according to conventional and unconventional sources between 2000 and 2019



Source: Secretaría de Energía (2020b).

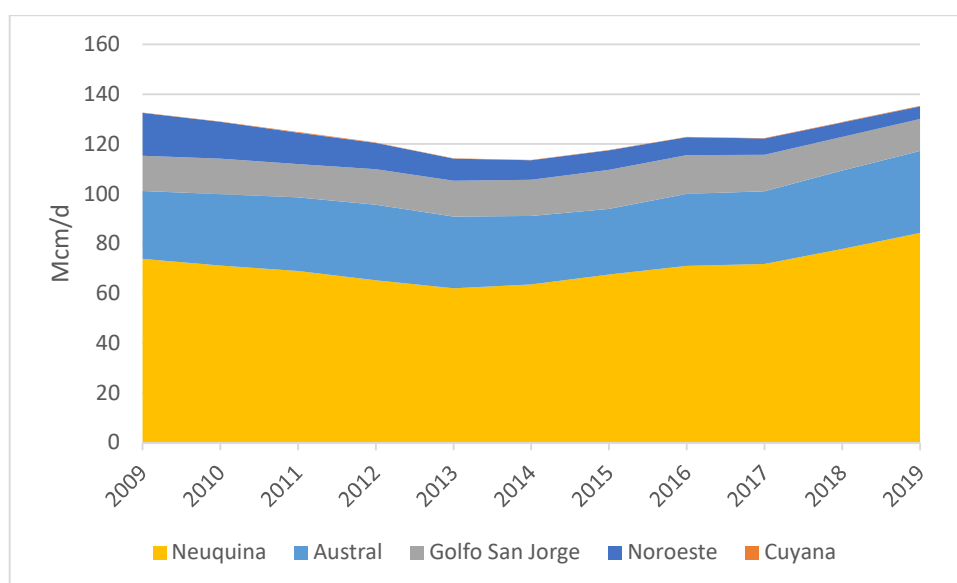
Considering the national production shared by reservoirs, Figure 20 reveals a divergent tendency for production from conventional and unconventional reservoirs in Argentina. Since 2004, the production from conventional reservoirs has been presenting a continuous decline, while that from unconventional reservoirs has been increasing.

In 2014, unconventional reservoirs' rising production overcame the declining output from conventional reservoirs, resulting in the first increase in the Argentinean national output since 2004. In more detail, after the national output achieves 142 Mcm/d in 2004, it starts a smooth to 113 Mcm/d in 2013. Between 2014 and 2019, the output from conventional reservoirs falls from 100 Mcm/d to 77 Mcm/d, while the output from unconventional reservoirs increases from 13.6 Mcm/d to 57.7 Mcm/d.

The Neuquén Basin leading the increase in national production since 2014

Inspecting the increase in national production starting in 2014, we observe that only two Basins, out of five, display an increased output between 2013 and 2019: Neuquén and Austral. In this period, the national production increases 18.3% while that of the Neuquén Basin increases 35.7%, and for the Austral Basin, 14.5%. The other Basins, Golfo de San José (GSJ), Noroeste, and Cuyana, accumulated a decrease of -10.5%, -43.5%, and -13.9%, respectively. In 2019, natural gas production from Neuquén achieved 62% of the Argentinean output, while the Austral Basin's participation reaches 24.4% (Secretaría de Energía 2020b). Figure 21, below, illustrates the natural gas production in Argentina between 2009 and 2019 according to Basin.

Figure 21 – Natural gas production in Argentina by Basin between 2009 and 2019

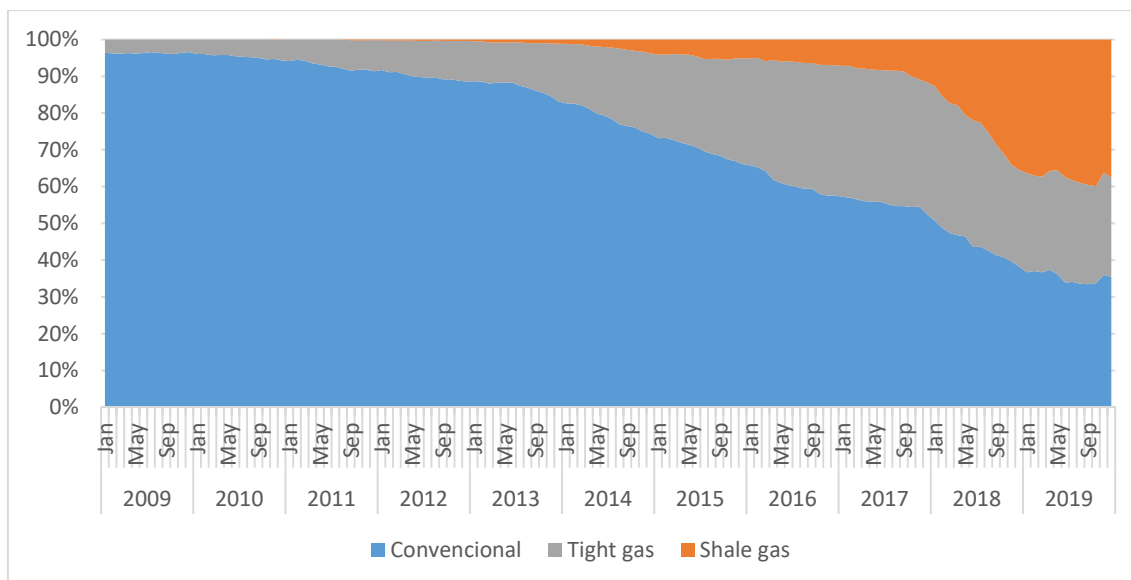


Source: Based on Secretaría de Energía (2020b).

Investigating the Neuquén Basin data, the production from unconventional reservoirs leads to this increase in the national output. It substantially increases between 2009 and 2019, from 2.7 Mcm/d to 54.5 Mcm/d, raising its share in whole regional production from 3.7% to 64.7% in the same period (Secretaría de Energía 2020b). Figure 22, below, shows the production

from the Neuquén Basin in conventional, tight gas, and shale gas, demonstrating the increasing participation from unconventional reservoirs.

Figure 22 – Natural gas production in the *Vaca Muerta* region according to conventional, tight, and shale reservoirs



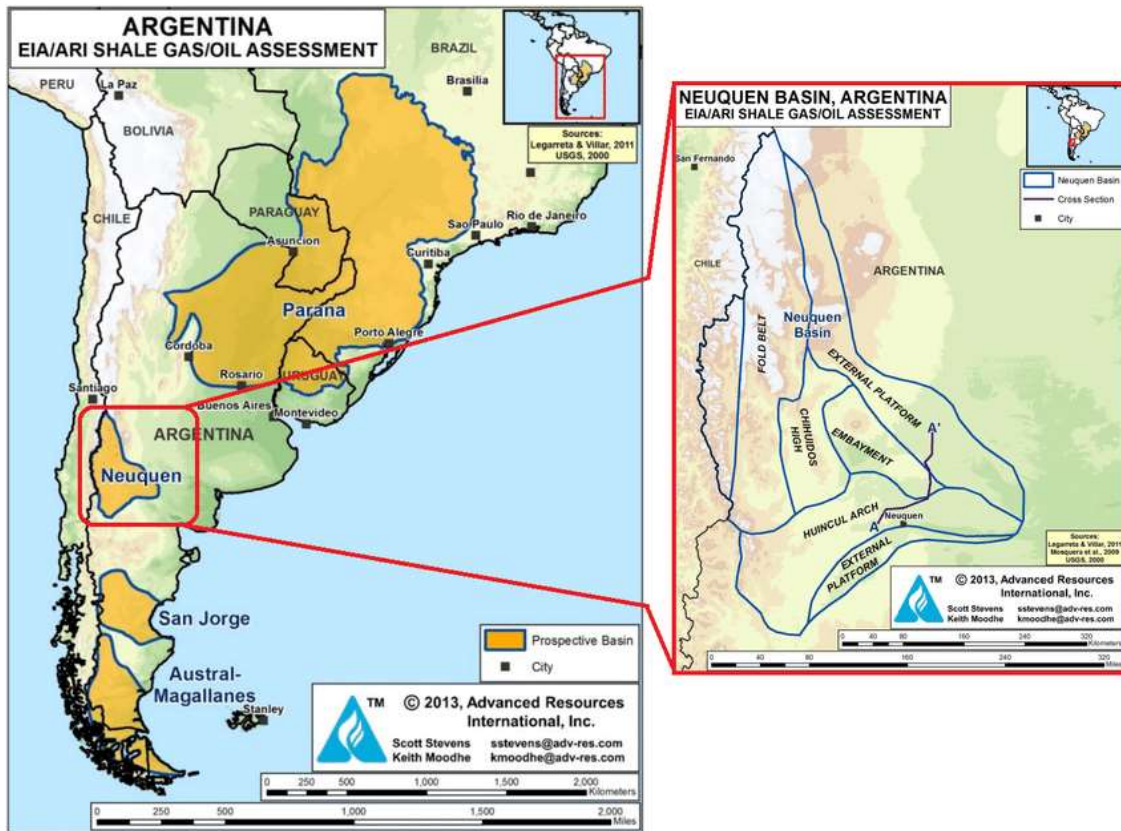
Source: Based on Secretaría de Energía (2020b).

Examining only the production from unconventional reservoirs (tight and shale) in the *Vaca Muerta* region, until 2014, tight reservoirs represent more than 90% of the whole production. Since then, the shale reservoirs' share progressively increases, reducing the tight share. In 2018, the shale formations' output overcame 50% of the total natural gas production in the *Vaca Muerta* region (Secretaría de Energía 2020b).

The *Vaca Muerta* region

Figure 23, below, presents the prospective unconventional shale reservoirs in Argentina, comprising four main Basins. The biggest represents the Paraná Basin in the north. At a central position depicted in a zoomed-in view, we have the Neuquén Basin which encompasses the *Vaca Muerta* region, the center of our analysis. At the extreme south, we have the Austral-Magallanes Basin, while the San Jorge Basin is located just above it, in the south of the country.

Figure 23 – Argentinean prospective unconventional shale reservoirs in Argentina with an emphasis on the *Vaca Muerta* region.



Source: Reproduction from EIA (2013, 2–9).

The *Vaca Muerta* region encompasses unconventional formations segregated into shale and tight sandstone. The shale reservoirs, the most vast and world-recognized, include the two best known, *vaca muerta* and *los molles*. The first formation is the most relevant, giving its name to the region, while the second is less abundant. The tight sandstone formation encompasses six formations, which are known by their high natural gas potential production. These are: *lajas*, *punta rosada*; *mulichinco*; *agrio*; *precuyo*; and, *lotena*¹²⁸. In 2018, these formations (shale and tight) were responsible for almost 99% of the whole *Vaca Muerta* regional production, proving their relevance for this area.

When talking about *Vaca Muerta*, it is relevant to separate the region from the geological formation. In this thesis, when referring to the *Vaca Muerta* region, we are encompassing the set of unconventional formations of the Neuquén Basin located in west-central Argentina,

¹²⁸ There are others formations, less relevant as: *lotena*; *quintuco*; *sierras blancas*; *tordillo*; *agrio*; *loma montosa*; *centenario*; and, *chachao*. Instead of all these formations are encompassed by the *Vaca Muerta* region, they present low production levels or even irrelevant at this moment.

including the Argentinean Provinces of *Neuquén*, *Mendoza*, and *Río Negro*. The *Vaca Muerta* region occupies a total area of 107.6 thousand km², being delimited by the Andes Mountains on the west and the Colorado Basin and North Patagonian Massif on the east and southeast, as represented in Figure 23.

When referring to the production from *vaca muerta* reservoirs, we incorporate the output from both shale reservoirs, *vaca muerta* and *los molles*. In this case, the production from these reservoirs represents a share of that of the *Vaca Muerta* region. Consequently, to prevent any misunderstanding with these denominations, we utilize the *Vaca Muerta* region term for the unconventional reservoirs in the Neuquén Basin and when referring to *vaca muerta* formations we will specifically denominate unconventional shale reservoirs.

Similarly to the Barnett shale region in the US, the *Vaca Muerta* region has hosting E&P activities dedicated to exploiting the zone's conventional reservoirs, thus, the region has the necessary infrastructure to support E&P activities. Conversely to the Barnett shale, the *Vaca Muerta* region also has unconventional tight reservoirs, which allow the adaptation of HF and all of the necessary additional infrastructure in the region through vertical wells, which are notably less expensive than horizontal wells. This element enhanced the E&P activities relating to introducing these technologies in this region and, consequently, the learning curve.

3.1.1 The Argentinean context: from exportable surpluses to the edge of natural gas shortage

In Argentina, the substantial discoveries of natural gas fields in the 1960s and 1970s drive the country to construct the necessary pipelines to replace other imported energy sources (firstly coal and, secondly, oil), saving external currency and avoiding deteriorating the country's balance of payment. This expansion of both supply and demand is only possible by keeping the natural gas prices highly competitive when compared with their peers. In a context of plentiful natural gas reserves and production (generating exportable gas surpluses), Argentina liberalizes its natural gas market between the 1980s and the 1990s. However, the vast 2001 crisis reversed the price liberalization.

After the 2001 crisis and ensuing re-institution of governmental natural gas price control, we observe three direct effects on the natural gas market: an increasing tightening between supply and demand, leading the country to face a supply crisis in 2004; growing imports associated with a decreasing domestic production, resulting in external natural gas dependence after 2007; and, a decreasing R/P indicator shaping a dismal perspective for natural gas external

dependence. Only the increasing exploitation of unconventional reservoirs in the *Vaca Muerta* region reduces external dependence.

Examining the particular Argentinean context after the US case allows us to offer an analytical contrast between both. This thesis identifies five remarkable differences. First, in Argentina, the external natural gas dependence unfolds in macroeconomic problems, given the restrictions on external currency to provide the payments for natural gas imports, while in the US, the main concerns are energy security and future embargoes. Second, in Argentina the natural gas is the first primary energy source since 1995 with significant participation of the household and electric power sectors, while in the US, natural gas intercalates between second and third primary energy source. Third, the US government never directly exploits O&G, while the Argentinean government creates its National Oil Company (NOC), *Yacimientos Petroliferos Fiscales* (YPF) for the distinct purpose of exploiting national resources. Fifth, in Argentina, the expansion of the pipeline network is associated with a state company, while in the US, this sector is dominated by private investment.

Concerning the similarities between both cases, we identify six main elements. First, demand grows according to supply capacity, resembling an initial expansion characterized by a government price control that favors consumers. Second, both countries face similar problems in natural gas supply. While the US confronts difficulties concerning its natural gas supply beginning in the 1970s due to the energy crisis (oil shocks) associated with an insufficient national natural gas production, Argentina reaches a supply crisis in 2004. Additionally, the Argentinian natural gas supply problems evolve to an external natural gas dependence on 2007. The US faces external dependence and its side effects starting in the 1970s. Third, the supply constraint's leading cause is the government price control (independently of its drivers). Fourth, the supply constraint occurs when the R/P indicator achieves values close to 10. Fifth, the decreasing natural gas production results from the incapacity of increasing extraction from conventional reservoirs. Sixth, the decreasing tendency in national natural gas production is only overcome through amplifying extraction from unconventional reservoirs.

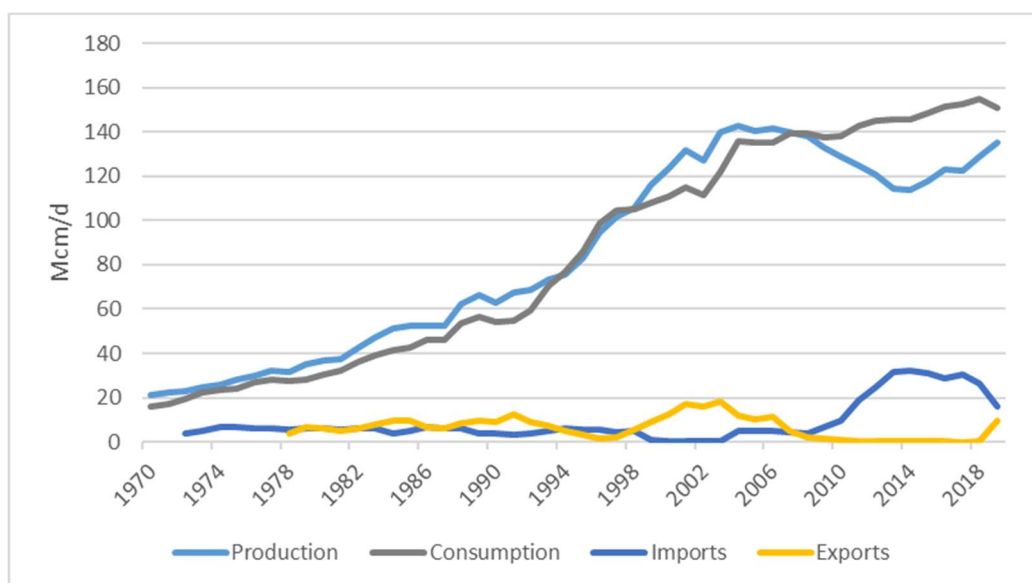
The following section is divided into four sections. They describe the progressive reliance on natural gas to fulfill energy demands, the external dependence due to the 2001 crisis, and the government's natural gas price control.

3.1.1.1 The declining tendency in the national production terminated by the extraction from unconventional reservoirs

Comparing the dynamics between supply and demand in both US and Argentina, we observe a similar behavior. Both countries expand the national demand according to national production until a supply crisis occurs. After the crisis, the increase in national demand begins to be satisfied by external sources. Finally, the increasing external dependence on natural gas is prevented with the growing output from unconventional reservoirs.

The Argentinean supply, demand, imports, and exports are presented in Figure 24, below. We can observe four main features. First, national consumption has been continuously growing. Second, national production presents a continuous growth until the 1990s, decreasing in the 2000s and increasing since 2014. Third, despite the lower levels of imports and exports, until the 2000s, Argentina has been a net natural gas exporter, reversing to a net importer after 2007. Fourth, net imports have been decreasing since 2015.

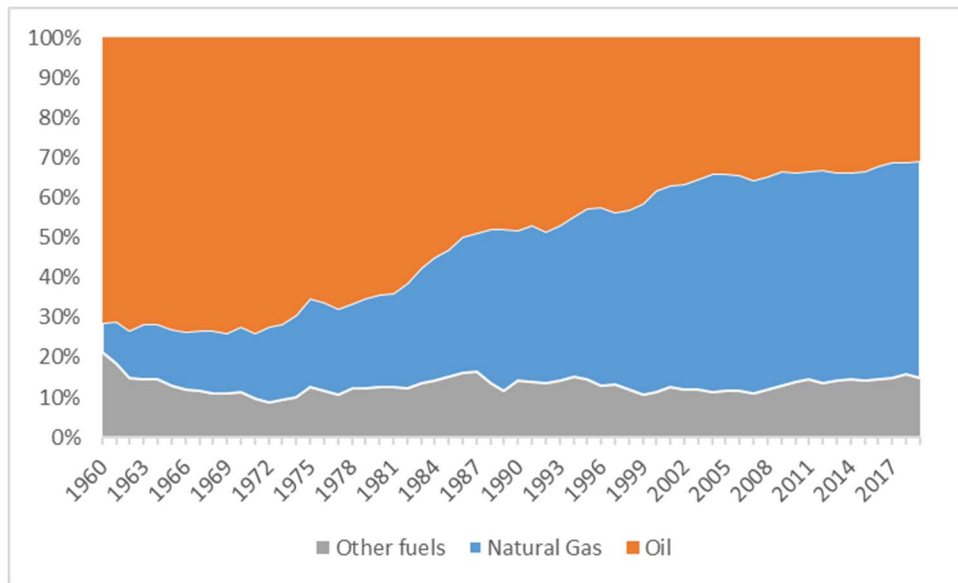
Figure 24 – Natural gas gross production, consumption, imports, and exports in Argentina between 1970 and 2019.



Source: Based on BP (2019), Secretaría de Energía (2020b), ENARGAS (2020), IAPG (2019).

Figure 25, below, demonstrates natural gas' participation in Argentina's primary energy consumption between 1960 and 2019. From an initially marginal role at the beginning of the 1960s, after the 1990s natural gas becomes the largest energy source, overcoming oil.

Figure 25 – Argentina’s primary energy participation between 1960 and 2019



Source: Ministério de Energía (2019).

Figure 25 exposes the country's reliance on two main sources, oil and natural gas, rising from 79% of the total primary consumption in 1960 to 85% in 2019. Particularly noteworthy is the replacement of oil by natural gas in this period. In 1960, oil participation achieves 71.5%, while natural gas reaches merely 7.2%. In 2017, oil participation falls to 31.2%, while natural gas participation substantially increases to 54%. At the beginning of the time series, the growing participation of natural gas occurs to the detriment of other fuels, notably imported coal¹²⁹. After the first oil shock in 1973, the increasing natural gas share is associated with a net reduction in the oil share. This movement is intensified subsequent to the second oil shock, which occurs in 1979. Finally, in 1995, the natural gas share overcomes oil, revealing the country's reliance on this energy source to satisfy its energy demand.

3.1.1.2 Deterioration in the R/P indicator

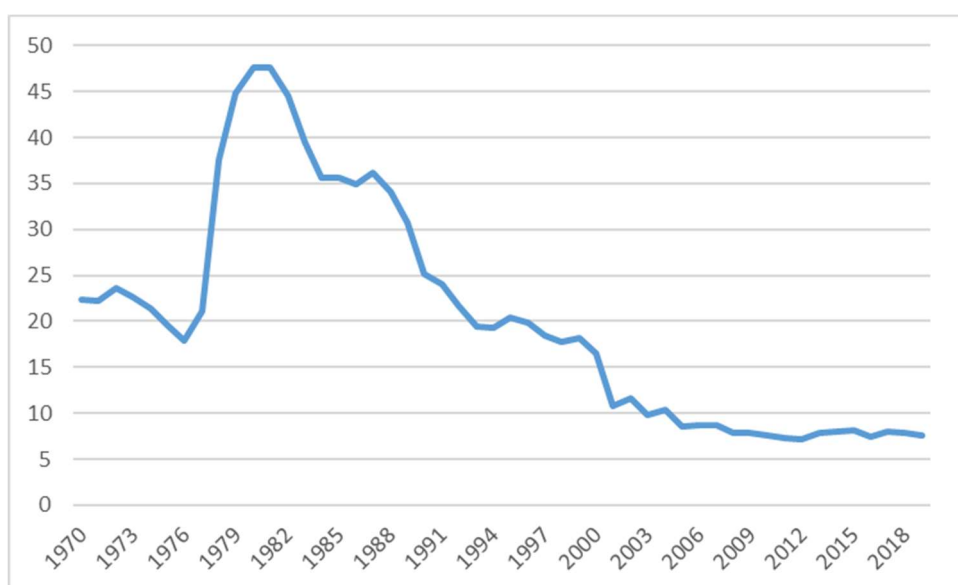
The R/P indicator follows a similar dynamic in both cases. After it achieves a peak revealing an abundance of natural gas reserves, it progressively decreases. Additionally, at the point at which this indicator achieves values close to 10 years, both countries suffers from a supply crisis. We emphasize that this ratio is a relevant indicator regarding extraction levels and reserves, given that it reveal how many years are left to exhaust the resource at the current extraction

¹²⁹ The coal participation continuously decreases from 6.3% in 1960 to less than 3% in 1964, demonstrating a prompt replacement of coal by natural gas. After 1964 the coal resumes its declining trajectory reaching less than 2% in 1981 and less than 1% after 2000. Since 2000 the coal participation hovers around 1% of the whole primary energy consumption in the country (Ministério de Energía 2019).

pace. Thus, while low levels of R/P show a possible resource exhaustion in the next few years, higher levels demonstrate a comfortable situation considering the actual circumstances.

Observing the evolution of this indicator, we can distinguish two periods in Argentina. The first period, from 1970 until the beginning of the 1980s, is marked by a significant improvement in this ratio, primarily based on the plentiful discoveries of the 1960s and 1970s. The first available data, in 1970, demonstrates a comfortable level higher than 20 years, mostly because of the start of the *Campo Durán* exploitation in the 1960s¹³⁰. Figure 26 details this indicator's movements.

Figure 26 – The R/P indicator for Argentina between 1970 and 2019



Source: Based on Secretaría de Energía (2020b).

Figure 26 shows that during the 1970s, the indicator improves, almost achieving a remarkable level of 50 years. This impressive boost results from the *Loma la Lata* discovery in the Neuquén Basin, the largest natural gas reservoir in South America, a singular field that more than doubles the country's reserves from 246 Bcm in 1977 to 641 Bcm in 1980¹³¹. After this

¹³⁰ Despite YPF discovered this field in 1951 in Salta's northwest province, the pipeline connecting this relevant natural gas discovery with the capital, Buenos Aires, started its operation in 1960 with a total length of 1 744 km and a nominal capacity of 9.7 Mcm/d (IAPG 2009, 30–31; Risuleo 2010, 12). The pipeline expansion in 1972 guarantees the delivery of a growing production, more than doubling the initial capacity, reaching 22.7 Mcm/d (Secretaría de Energía 2020b).

¹³¹ In 1977 Esso (under a contract with YPF) discovers this natural gas field in the Neuquén Basin. The first evaluation reveals that it almost double the country's proved reserves, from 246 Bcm in 1977 to 432 Bcm in 1978. After several investments in this field, only their proved reserves achieve 320 Bcm of natural gas associated with 377 Mbbl of condensate. Thus, the first evaluation sub-estimated the field's reserves,

discovery, the natural gas reserves overcome oil reserves, highlighting the availability of natural gas resources in Argentina (IAPG 2009, 31; Hechem 2010, 10; Blanco et al. 2018, 126;148). The R/P indicator reflects this achievement, substantially increasing in value from 18 years in 1976 to 47 years in 1980, the highest value in the country history (Secretaría de Energía 2020b).

Since 1980, the second period is characterized by a gradual deterioration of the ratio, and reflects the progressive tightening between supply and demand, which intensifies in the 2000s. In the 1980s and the 1990s, this indicator progressively falls, indicating two elements. The first is the absence of substantial discoveries of new natural gas fields (compared with the massive findings of *Campo Durán* and *Loma la Lata*). This element limits the reserves' expansion beyond the record level of the 1980s. The second is the progressive increase in natural gas extraction based on the gradual development of the pipeline network¹³² to satisfy increasing demand. Therefore, from a comfortable level close to 50 years, the R/P indicator continuously falls, achieving an average of around 20 years by the 1990s.

After the 2001 crisis, the R/P indicator substantially drops, chiefly due to the reestablishment of the government control on natural gas prices (explained in more detail in section 3.1.2.3). In a context of prices falling, the reserves shrink from a historical peak of 748 Bcm in 2000 to 438 Bcm in 2005, representing a reduction of 43% in the reserve level over a five year period (Secretaría de Energía 2020b; Ministério de Energía 2019). We emphasize that this decrease in reserves is superior to the total extractions in this period, being the difference justified by a reclassification between the different categories of reserves, from proved to possible. Several companies justified this re-classification because of the wellhead natural gas price reduction caused by government measures to limit the 2001 crisis' economic consequences (Kozulj 2005, 30–33). This substantial reduction in reserves negatively influenced the R/P indicator, which achieves an average of 10 years in the 2000s, and 7.7 years in the 2010s, indicating a negative perspective regarding the national output's potential to supply further demand.

being it 1.3 times higher than the country' total natural gas proved reserves in 1977 (Hechem 2010, 10; Blanco et al. 2018, 148).

¹³² To provide access to the *Loma la Lata* discovery, the *Gas del Estado* inaugurates in 1981 the central pipeline named Neuquén Buenos Aires (Neuba I). This pipeline lengths 1 600 km connecting the capital, Buenos Aires, and Chile's neighbor country, crossing the province of Neuquén (Risuleo 2010, 12–13; Blanco et al. 2018, 166–67). However, the overwhelming production from this field demands to construct other pipeline to flow its production to Buenos Aires. Thus, in 1988 it is inaugurated the Neuba II pipeline with an extension of 1 300 km and a nominal capacity of 30 Mcm/d (Risuleo 2010, 12–13; Blanco et al. 2018, 166–67).

3.1.1.3 The growth of external dependence

The comfortable reserves situation between the 1970s and the 2000s allows for an increase in national production, which justifies an expansion in the pipeline network associated with their connection with the neighboring countries of Bolivia, Chile, Uruguay, and Brazil. While the link with Bolivia allows for the importation of natural gas from this country since 1972¹³³, its connections with other countries allows to export natural gas surpluses starting in 1978¹³⁴.

Considering the balance between exports and imports, Argentina was a net exporter until 2007. Up to this period, Argentina exports natural gas to its neighboring countries of Chile, Brazil, and Uruguay, importing natural gas from Bolivia. Nonetheless, Argentina begins to gradually reduce its exports, and by 2007, it imports more natural gas than exporting it.

Since 2004, the path for a growing external dependence

Since 2004, Argentina has been increasing its import volumes initially through its usual supplier, Bolivia, and since 2008, from LNG terminals. To face the potential natural gas shortage in 2004, the country created a national company, *Energía Argentina Sociedad Anónima* (Enarsa)¹³⁵, which had a double objective: increase natural gas imports to satisfy national demand; and exploit O&G resources, expanding the country's reserves (IEASA 2017).

Analyzing the dynamics between supply and demand in the 2000s, we observe a difference in their growing pace, revealing a tightening in the natural gas market. While national production increases 3.6% per year between 2000 and 2004, demand rises 5.2% per year in the same period, increasing more than 10% between 2002 and 2003 (Secretaría de Energía 2020b; Ministério de Energía 2019; ENARGAS 2020). Kozulj (2005) affirms that the upsurge in vehicular consumption results from the controlled natural gas prices in a context of liberalization of other fuel prices, raising natural gas' competitiveness and achieving a price almost 70% lower than that of gasoline (Kozulj 2005, 26–28; Honoré 2004, 25). Considering the first quarter of 2003 and 2004, i.e., prior to the supply crisis, national demand grows 19% (ENARGAS 2020). From the 2003 supply and demand levels, Kozulj (2005) estimates that, if these levels increase according

¹³³ The pipeline from *Campo Durán* to Buenos Aires also enabled a connection with natural gas reserves from Bolivia since 1960. The first imports from Bolivia adds a flow of 4 Mcm/d in 1972, increased to 6 Mcm/d until 1999, when Argentina stopped with these imports, only re-established in 2004 (Secretaría de Energía 2020b; Risuleo 2010, 12).

¹³⁴ With the *San Sebastián - El Cóndor* pipeline exporting to Chile since 1978, crossing the *Magallanes* strait on the extreme south. In 1981, the pipeline *Centro Oeste* connected the Neuquén Basin with Chile, increasing the exports capacity (Risuleo 2010, 12–15).

¹³⁵ In 2017, the company changes its name to Integración Energética Argentina S.A. (IEASA) (IEASA 2017, 5).

to the previous pace of growth, national production will increase 5% while demand plus exports increase by 15%, revealing the extension of the supply crisis in 2004 (Kozulj 2005, 26).

In these circumstances, on 19 May 2004, the country faced a deficit of 27.3 Mcm/d, leading authorities to temporarily cut supply for industries. In June, the country's total deficit achieves the average level of 25 Mcm/d (Honoré 2004, 22). Facing a growing tightening between supply and demand, the government reduced its the voltage running through the national electric grid in 5% (from 220 to 208 volts) to prevent natural gas shortages. However, this measure lasted only for a single day, thanks to emergency electric power imports from Brazil that, totaled 500 MW or 2.5 Mcm/d. This extreme measure demonstrates the severe supply constraint leading the country to launch a plan focusing on shoring up the energy supply (Honoré 2004, 21; Presidencia de la Nación 2004, 4).

Finally, additional measures were applied to prevent shortages, notably an obligatory reduction in natural gas consumption during peak hours and a prioritization of the national demand to the detriment of exports¹³⁶ (Kozulj 2005, 30–52). These measures successfully prevented natural gas shortage in 2004. However, they paved the way for the external dependence on natural gas beginning in 2007.

The increasing national demand for natural gas is satisfied with growing imports. From an initial value of 7 Mcm/d in 2004, imports increase when Enarsa signs additional contracts with Bolivia to supply natural gas to Argentina¹³⁷. Although Bolivia's natural gas has a lower price than other sources of imports, Bolivia cannot provide all the natural gas required in Argentina, resulting in the initiation of Liquefied Natural Gas (LNG) imports in Argentina by Enarsa¹³⁸.

¹³⁶ Through the resolution 265 of 2004 the government determines the end of the exports if the national demand is in risky of shortage.

¹³⁷ In 2006, Enarsa signs an agreement with YPF to increase the Bolivian natural gas exports to Argentina to a maximum of 27.7 Mcm/d for 20 years. According with the contract, the volumes will gradually increase from the 2004 contractual level of 7 Mcm/d to 16 Mcm/d in 2008 achieving the plateau of 27.7 Mcm/d in 2010 (Gomes and Brandt 2016, 35; IEASA 2017, 25). Notwithstanding these terms, the government data demonstrate different volumes for natural gas imported from Bolivia. The imports from Bolivia starts in 2004 at 3 Mcm/d increasing to 6 Mcm/d between 2005 and 2010 (in 2008 it falls to 3 Mcm/d, recovering the previous level in 2009). In 2011 it increases to 9 Mcm/d, achieving 16 Mcm/d in 2012 (Lopetegui 2019, 6). Despite the imports at lower levels than the contractual definition, in 2012 the same companies agree to increase the volumes according with the YPF capacity, being defined for the first two years, an additional volume of 2.7 Mcm/d and 3.3 Mcm/d (Gomes and Brandt 2016, 35; IEASA 2017, 25).

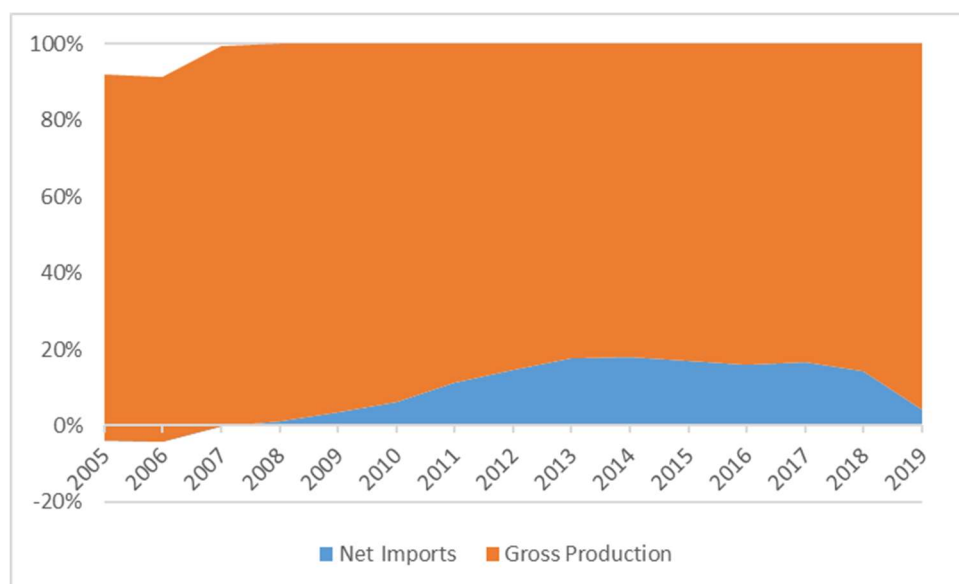
¹³⁸ Despite the increasing volumes imported from Bolivia, they are not enough to meet the Argentinian domestic demand. Thus, YPF launches the construction of two terminals to import LNG. The country starts the LNG imports in 2008 after the inauguration of the Floating Storage Regasification Unit (FSRU) terminal of Bahia Blanca, 640 km south of Buenos Aires, achieving an average of 1 Mcm/d in the first year. In 2009 the LNG imports increases to an average of 2 Mcm/d. Considering the several restrictions to increase even

Consequently, the Argentina's total natural gas imports experience a massive increase from 7 Mcm/d in 2004 to 31 Mcm/d in 2014 (ENARGAS 2020).

Simultaneous to the increase in imports, the exports quickly reduce from a historical peak of 19.9 Mcm/d in 2004 to 2.3 Mcm/d in 2008, achieving values close to zero in 2010¹³⁹ (ENARGAS 2020). In 2016, a high level of natural gas imports test the limits of the country's infrastructure, leading Argentina to begin LNG imports from Chile and, reversing the old export pipeline to be used for imports. Despite the high cost of proceeding with LNG imports from Chile, it is necessary to fulfill the country's necessities during the winter season (Gomes and Brandt 2016, 41; IEASA 2017, 27; Secretaría de Gobierno de Energía 2019a).

The net imports summarize all these dynamics between exports and imports. It is shown in Figure 27, below.

Figure 27 - Argentine natural gas production and net imports between 2005 and 2019



Source: Based on Secretaría de Gobierno de Energía (2019a, 3), and ENARGAS (2020).

more the supply of natural gas, YPF starts another FSRU terminal in 2011 in the Parana River, 50 km out of Buenos Aires. In this context, the LNG imports continuously increases achieving 5 Mcm/d in 2011, 11 Mcm/d in 2011 and 13 Mcm/d in 2012 (Gomes and Brandt 2016, 40; IEASA 2017, 25; Lopetegui 2019).

¹³⁹ The expansion in the natural gas production in the 1990s allows exporting the surpluses to neighboring countries, mainly Chile, with marginal volumes directed to Brazil and Uruguay. To face these exports, both the transport system operators and producers construct the necessary pipelines connecting neighbors' countries. Since 1996, the exporting capacity augments from virtually zero to 42.6 Mcm/d in 2001, performing a total investment of US\$ 964 million. These investments allow the exports to increase quickly achieving considerable values in 1997 (Kozulj 2005, 20; Vásquez 2016, 7).

Figure 27 shows that, since 2007, Argentina has been a net natural gas importer, gradually augmenting its energy dependence from 4% of its total natural gas demand in 2009 to more than 20% in 2013 (Secretaría de Gobierno de Energía 2019a, 3; ENARGAS 2020).

3.1.1.4 The economic consequences of external dependence for Argentina

In Argentina (and other Latin American countries), external dependence on imported manufactures, including oil products, associated with the exports of primary products leads the country to internalize the commodities' price volatility. In this case, these nations experience cycles of growth and depression based on the price of their main export commodity (in the Argentinean case: wheat; in the Brazilian case: coffee; in the Chilean case: copper, etc.). In this context, periods of high commodity price mean substantial GDP growth while years of low commodity price mean a deficit in the balance of payment (represented by the sum of both balances commercial and services), limiting GDP growth.

In the short term, the commercial deficit may be financed by increasing external debt. However, in the long term, the country has to produce some positive values on the balance of payments to reduce its previous debt. The necessary balance in the long term (or until international investors agree to finance consumption through debt) represents a constraint to internal growth, also named external strangulation. The Latin American economic cycles in the XX century are usually explained through the commercial balance dynamics and their recurrent external crisis, propelling these countries to adopt import substitution industrialization (ISI) as a strategy to attain a triple objective: first, to reach the industrialization level of central countries; second, to reduce their external dependence; and, third, to control the country's economic cycles (Kaplan 1992, 18–22).

Conversely to the US case, in which where the main undesirable feature of energy dependence is the possibility of external constraint based on political reasons (as in the first and second oil shocks), in Argentina, the undesirable feature is its constraints on GDP growth. In this case, the balance of payments limits economic growth, also triggering periods of macroeconomic volatility associated with inflation, amplifying an economic crisis with possible political side effects. Argentina has faced these kinds of problems three times in its history, mainly driven by its external energy dependence. The first occurred in the 1950s, the second in the aftermath of the first oil shock (in 1973) and, the third after the second oil shock (in 1979), reverberating in the 1980s in successive economic crisis.

The progressive natural gas external dependence after 2004 has been affecting the Argentinean government through two elements. First, by increasing spending with natural gas

subsidies directed to consumers. Second, by deepening the restrictions of external currency in order to proceed with imports. Considering that natural gas is the first primary energy source for Argentina, these elements negatively influence the GDP potential growth.

To alleviate the social repercussions from the 2001 crisis and prevent an escalation of inflation, the government has been subsidizing natural gas imports (notably more expensive than the nationally produced fuel). In these circumstances, the difference between the international natural gas price and domestic prices is financed by the government budget, raising the costs with energy subsidies. Thus, the government's expenses for the energy subsidies increase according to the difference between the national values and the international prices, affected by the import volume. In the context of falling domestic production and growing demand, the government has expensed energy subsidy increase since 2004¹⁴⁰.

Additionally, the balance of payments continuously deteriorates, becoming negative in 2015, mainly driven by the energy sector. The increasing imports of LNG are among the causes of commercial balance deterioration (Gomes and Brandt 2016, 5–6), limiting external currency availability¹⁴¹. This context adds pressure for the government to reduce natural gas import levels, raising the relevance of natural gas external dependence.

3.1.2 The government reaction to the economic crisis leading Argentina to a supply crisis

The supply crisis and growing external dependence result from the government's price controls that were re-established after the severe 2001 economic crisis. After market liberalization completed in the 1990s, Argentina faced the largest economic crisis in its history, forcing the government to control the natural gas price in order to alleviate the crisis' social impacts.

We highlight that Argentina's economic crisis has a considerable influence in implementing reforms of the regulatory framework, motivating this thesis to describe these reforms as a relevant component that significantly shaped the country's context. Additionally,

¹⁴⁰ Between 2011 and 2012 the imports bill more than doubles, achieving US\$ 3.78 billion (Argentina 2013, 2). We highlighted that the original value are in *pesos* of 17.3 billion. In this case we used the average value of 4.57 *pesos* for each US dollar to proceed with the conversion (Ministério de Hacienda 2020).

¹⁴¹ The availability of US dollars in Argentina is pressed by the Argentina's bonds renegotiation from the previous *default*. Some funds do not accepted the government terms, proceeding with a judgement in US (Gomes and Brandt 2016, 7).

while the US' concerns about external dependence are based on energy security, for Argentina, these concerns are centered on economic issues.

Comparing the Argentinean supply constraint with that of the US, we conclude in a similar driver: the government price control. Both countries controlled natural gas prices, reducing them compared with their possible substitutes. This relative price reduction enhances natural gas' competitiveness, stimulating its consumption to the detriment of other fuels. In a context of plentiful reserves associated with a growing national supply satisfying the main share of the national demand, this price control is enough to balance the market. However, the tightening between supply and demand, mainly caused by insufficient supply growth, is not captured by prices, leading both countries to a supply crisis. While the US suffers two consecutive natural gas shortages in the winter seasons (1975/76 and 1977/78), Argentina manages its supply crisis quickly increasing imports and controlling demand, and preventing a shortage in the 2004 winter season. The following section provides more detail about Argentina's gradual liberalization process, the severe crisis in 2001 that reversed the price liberalization, and the subsequent 2004 supply crisis.

3.1.2.1 A gradual price liberalization process

Despite the government reformulation in the regulatory framework of E&P (mainly focused on the participation of private companies) between 1920s and the 1980s, in the natural gas production or distribution sector there are not a substantial change. As our primary interest is the natural gas market, this thesis disregarded these marginal changes in the previous regulatory framework based on the monopoly executed by YPF and *Gas del Estado* (briefly described in Box 7, below), focusing on reforms molding both the E&P sector and the natural gas market resulting in the 2004 supply crisis.

Box 7 - The historical regulatory framework based on the state monopoly

Since the beginning of O&G production in Argentina, as previously emphasized by several authors (Kozulj 2002; Gadano 1998; Gomes and Brandt 2016), the national regulatory framework has moved like a pendulum between market liberalization and governmental control. These analyses focused on the E&P sector are primarily motivated by the oil market circumstances instead of the natural gas dynamics.

Until the 1950s, Argentina is strongly dependent on coal to satisfy its energy demand, being the national production inexistent. Consequently, the first oil discovery in 1907 reveals the possibility of supplying energy demand by exploiting national sources. To prevent foreign companies from controlling these resources, the government increased state control in the O&G sector through three key elements.

First, it proposed establishing a state monopoly in the O&G sector in 1922 and the creation of its NOC, YPF. While the national congress refused the state monopoly, the creation of YPF was approved (Blanco et al. 2018, 50–56). Second, in 1932 through law 11 668, YPF was converted into the governmental body to manage O&G policy and develop E&P activities on the government's behalf (Blanco et al. 2018, 59). Third, in 1935 the Reserve Law (law 12 161, also named the Petroleum law) is enacted, delimiting some areas for exclusive YPF exploitation. In this case, the law reserves O&G prone areas to the state

company, limiting private involvement and creating a state monopoly operated by YPF in these ‘reserved’ areas (Argentina 1935, chap. V).

Focusing on exchanging imported fuels with nationally-produced natural gas, the government creates *Gas del Estado*, a new company replacing YPF in the gathering and distributing of natural gas. Reflecting the growing interest in expanding state control in the O&G sector, in 1945, the government expropriates the gas distribution in the biggest market, Buenos Aires (previously authorized through a concession to private investors – British capitals), grating it to *Gas del Estado*¹⁴² (IAPG 2009, 29; Risuleo 2010, 6; Miganne 2010; Blanco et al. 2018, 94–95). Since the 1950s, this regulatory framework has been moving like a pendulum between the authorization and the prohibition of private participation in the E&P sector.

Considering the regulatory framework, prior to the supply crisis of 2004, Argentina had liberalized natural gas prices, opening up its E&P market and privatizing its NOC, YPF. However, the 2001 economic crisis drives the government to re-established the price control, leading the country to a supply crisis in 2004 and, and after 2007, an increasing external natural gas dependence. Similar to the US case, we conclude that the Argentinean market imbalances are a result of the government’s price control.

3.1.2.2 The liberalization process of the gas industry until the 2001 crisis

In 1978 the government enacts law 21 778, delimitating the possibility to directly sign E&P contracts with private investors, meaning the loosening of YPF’s monopoly in the E&P sector. To enhance the contract's attractiveness, the law offers the liberty to dispose of O&G production (with a prioritization to supply the domestic market by the same international price). Nonetheless, the government retains the price control, guaranteeing to investors a future parity with oil's international values (Blanco et al. 2018, 143–44; Gadano 1998, 11).

In 1985, to deal with an economic crisis that started in 1981 after the second oil shock, the government launches the plan ‘Houston’ to improve oil’s indicators, notably to increase E&P activities and recover the previous R/P levels¹⁴³. The plan aims to increase private participation

¹⁴² The company is named as *Dirección General de Gas del Estado* starting its actuation before, yet during the 1930s as the YPF’s gas department. Additionally, the expropriation happened in 1940 being followed of a judicial discussion until the final decision in 1945 (Castro 2010). Finally, between 1943 and 1955 there are several changes on government bodies to handle with the complex environment in Argentina. Among them we quote the decree 12 648 of 1943 representing the first consolidation of the government bodies focused on energy in Argentina. By this decree the government creates the *Dirección Nacional de Energía* (DNE) encompassing four major government bodies: *Dirección General de Gas del Estado*, *Dirección General de Centrales Eléctricas del Estado*, *Dirección General de combustibles vegetales y derivados* and the *Dirección General de combustibles sólidos minerales*. YPF is set as a state company, changing its formal name to *Dirección General de YPF*. In 1950, the government starts another round of consolidation, creating the *Empresa Nacional de Energía* to gather all government actuation reducing the YPF independence. However, in 1955 the *Empresa Nacional de Energía* is closed, emerging two main companies in the O&G sector: YPF and *Gas del Estado* (Alonso 2018, 31–32; Argentina 1943; Blanco et al. 2018, 94–97).

¹⁴³ The R/P indicator for the oil case presents a continuous decline between the 1970s and the 1980s, starting at 17.2 years in 1970 and finishing at 12.5 years in 1989 (Secretaría de Energía 2020b).

in some previously YPF-controlled areas. Through this plan, the government signs 165 contracts of E&P rights through international bid rounds (Blanco et al. 2018, 143–44; Gadano 1998, 11).

The regulatory framework basing O&G's market opening

A new government concerned with the severe economic depression in the 1980s¹⁴⁴ introduces several measures to deal with hyperinflation and the government deficit, including a restructuring of the state role across all economic sectors, including the O&G. Thus, the government gradually reduces its participation in the national economy, implementing measures to raise competition among private agents and leaving private companies to supply consumers.

Focusing on the O&G sector, the government proposes privatizing the state companies YPF and *Gas del Estado*, proceeding with other arrangements to prevent market power accumulation by a participant (Kozulj 2002, 14; Gadano 1998, 15–16). Although YPF is more relevant and representative, the privatization of *Gas del Estado* and the reorganization of the transport and distribution networks are prioritized. This reorganization in the regulatory framework is made through three phases.

The first phase starts in 1989, with the decrees 1 055, 1 212 and, 1 589. Each decree delimits a government objective: to increase the output in marginal production areas under YPF control; to deregulate hydrocarbon prices; and, to increment competition in the market enhancing the degree of liberty.

Among other measures, these decrees conclude in the government power to define prices, including of oil products, eliminate the obligation to sell the O&G produced to YPF, guarantee the liberty to allocate the production or even export it, and define YPF's marginal fields¹⁴⁵ foreseeing privatizing them. Particularly in the natural gas market, the government sets in motion progressive price liberty according to increases in the number of agents. Finally, the

¹⁴⁴ In Argentina, the 1980s are market by two main crises. The first in 1981 as a result of the second oil shock and the second in 1988. Although the economic crisis started in 1988, its effects increase in 1989 and are widely disseminate in 1990. Gadano (1998) shows the progressive deterioration of the main macroeconomic indicators between 1988 and 1989. In 1988 the GPD falls -2% and in 1989 it falls -7%. The inflation jumped from 343% in 1988 to 3 079% in 1989. Finally, the government deficit increases from 7.9% of GDP to 8% in 1989 (Gadano 1998, 15). The IMF estimates the inflation in 1990 at 12 000% per year and the government deficit at 16% of GDP (Wijnholds 2003, 104).

¹⁴⁵ The marginal areas are defined by a production inferior to 1 200 bbl/d or without production during the last five years (Argentina 1989a).

government proceeds with converting what were previously YPF contracts into concession¹⁴⁶, scheduling several bid rounds¹⁴⁷ to resume the opening process in the E&P sector (Argentina 1989b; 1990; IAPG 2009, 51).

The second privatization phase involves the creation of a new structure in the natural gas transport and distribution sectors. This measure aims to stimulate competition between agents where possible, and to prevent any one player from holding enough power to influence the market. In these circumstances, law 24 076 of 1992 establishes a market organization in the natural gas distribution system and authorizes *Gas del Estado's* privatization. Synthetically, the regulatory framework encompasses E&P activities and the transportation and distribution systems related to natural gas. In the E&P sector, free competition delimits the wellhead natural gas price, while in the transportation and distribution systems, their monopolistic characteristic requires state regulation. Thus, the law creates a regulatory body, the *Ente Nacional Regulador del Gas* (ENARGAS), to supervise the gas transport and distribution system and prevent any anticompetitive activities¹⁴⁸ (Argentina 1992; ENARGAS 1994, 15–30).

Finally, this law divides *Gas del Estado* into ten companies, delimiting the interaction among them, determining the unbundling process, and establishing free access to the gas transport system. Thus, *Gas del Estado* is split into two segments, the first encompassing the transport system represented by the national network of pipelines, and the second representing the local distribution network. The law determines the transport system's division into two pipeline companies (north and south), which are responsible for transporting fuel from producers to the distribution network. The distribution network is geographically shared by eight companies that operate a monopoly in their regional system (Metrogas, GasBan, Cuyana, Centro, Litoral, GasNor, Pampeana, and Sur). All these new companies are sold to different

¹⁴⁶ Gadano (1998) explains the parameters to convert the YPF contracts in concessions ones. From 24 YPF contracts, initially only 15 were converted in concessions on January 1991 while the other 9 were in dispute. These disputes were fully settled on October 1991 (Gadano 1998, 19–21).

¹⁴⁷ To resume the bid rounds, the government split some YPF E&P areas on central and marginal, defining four areas as central and more than 100 as marginal. In 1990 the government sold the four central areas achieving the value of US\$ 813 million for them. The quantity of marginal areas makes the government offer them in several bid rounds between 1990 and 1992, signing 73 concessions contracts for US\$ 433.5 million. In these bid rounds, the local companies holding contracts with YPF are the main winners as Pérez Compac, Astra, Tecpetrol and Cadipsa (Gadano 1998, 17–18).

¹⁴⁸ Additionally, the price regulation follows the principle of a price cap, delimiting the maximum value for the transport and distribution, being this ceiling review each five years. The price encompasses a remuneration for the previous investment, the recovery of the costs and a 'reasonable' profit compared with other economic activity with similar risks (Gadano 1998, 24).

agents, achieving the value of US\$ 2.2 billion (Argentina 1992; Gadano 1998, 23–25; ENARGAS 1994, 15–30).

The third phase is the privatization of YPF, in preparation since 1989, with the marginal and central areas' bid round. Prior to the complete privatization of the company, YPF sells other assets, summing the value of US\$ 896,5 million¹⁴⁹. In 1993, law 21 145 authorizes the government to sell 15% of YPF. This partial privatization achieves the amount of US\$ 4.3 billion. Additionally, this law also converts all YPF areas into E&P concessions or licenses, resulting in 50 concessions contracts and 24 exploration licenses. Finally, in 1999 the government sells the remaining 85% of YPF to Repsol for US\$ 13.1 billion (Gadano 1998, 15–25; IAPG 2009, 25; Vásquez 2016, 6).

Summarizing, in the 1990s, changes in the regulatory framework guarantee a liberalized market in the E&P sector associated with the government's relinquishment of the natural gas price control. Thus, beginning in the end of the 1980s, private participation in the E&P of O&G through concession contracts becomes possible. Additionally, since the privatization of *Gas del Estado* in 1992, the transportation and distribution systems have been owned by private companies. Finally, in 1993 the government starts to sell its NOC, YPF, terminating its participation in the E&P sector in 1999.

3.1.2.3 The wellhead natural gas price dynamics

The government has been controlling the wellhead natural gas price as a mechanism to stimulate its utilization. The contracts granted to private investors in the 1980s to proceed with E&P activities reveal an energy policy for natural gas prices that is based on wellhead price controls. Despite a liberalization in the 1990s, the 2001 economic crisis reverses this price liberalization, temporarily re-establishing the wellhead price control to alleviate the social and economic consequences from the crisis. It is mainly the price control that leads the country to a supply crisis in 2004, which is only overcome through increased imports, resulting in an undesirable external dependence on natural gas beginning in 2007¹⁵⁰.

¹⁴⁹ These other assets encompasses the downstream sector and other non-related O&G sector, as: refineries, port terminals, airplanes, and transportation equipment (Vásquez 2016, 6).

¹⁵⁰ Honoré (2004) analyzes the 2004 supply crisis listing additional elements than the government price's control as drivers for the supply crisis. Among them the author quotes the crisis after the *pesos* devaluation reducing the necessary investment; the high seasonality of demand in Argentina and Chile (the main exporting country); and, the dry year demanding more electric generation from termoelectrics (Honoré 2004, 19–21). Despite these additional elements shaping the supply crisis, the author affirms that the prices frozen after the 2001 crisis is the main leading cause for the 2004 supply crisis.

The historical government control on natural gas prices

In 1985, as a mechanism to open up and incentivize E&P activities, the government starts bid rounds to sign contracts between YPF and private investors under the Plan 'Houston' (as emphasized by section 3.1.2.2), guaranteeing the price of production. In the case of natural gas, the contract's clauses determine that the wellhead natural gas price will never exceed the value of 14% of the international oil price, considering the energetic equivalence between the fuels (Argentina 1985, para. 8: 'g'). In other terms, calculating natural gas wellhead price ceilings considering the different units and calorific power¹⁵¹, natural gas will never exceed 2.5% of the price per barrel. Thus, in light of an average Brent price in 1986 of US\$ 14.43 per barrel (BP 2019), in this same year, the natural gas price never exceeds, on average, US\$ 0.36 MBtu.

The comfortable situation provided by the substantial reserves associated with natural gas' growing production (explored in more detail in section 3.1.1) allows the government to keep its prices under control (more specifically, wellhead natural gas prices represents only a proportion of the oil prices). Prior to 1985, there was no available information about wellhead natural gas prices. However, as these contracts (signed since 1985) aimed to stimulate private investment in E&P activities, we can assume that wellhead natural gas prices are even lower than the 1985 level, representing the leading cause for the substantial rise of natural gas utilization in the country.

In 1987, the government reformulated the contracts inserting a price stimulus for natural gas through decree 623 (Blanco et al. 2018, 160–62). After this decree, the natural gas price cap is increased to 27%, leaving 14% as the minimum value (Argentina 1987, para. 8: 'g'). Considering the calorific power and oil price, these values range from 2.5% and 4.8% of the barrel price. Taking into account that the average Brent price in 1987 is US\$ 18.44 per barrel (BP 2019), in this year, the wellhead natural gas price ranges between US\$ 0.46 MBtu and US\$ 0.88 MBtu.

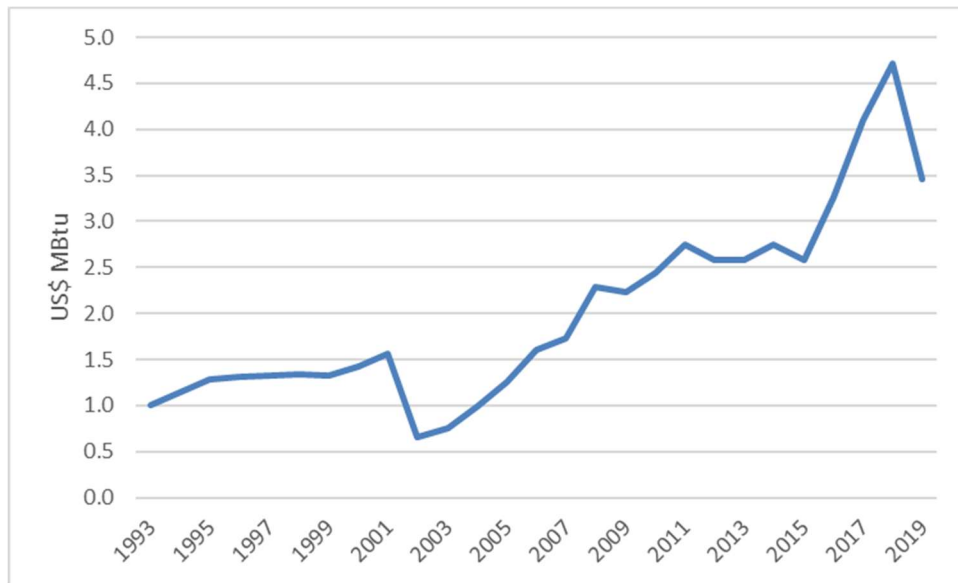
Price liberalization's effects

Since price liberalization occurred in the 1990s, natural gas prices have been increasing, falling only in 2002 and 2019¹⁵². Figure 28, below, shows the natural gas prices for the Neuquén region since 1993, the date of the first available data.

¹⁵¹ Assuming that each oil barrel has 5.551365 MBtu (EIA 2019f).

¹⁵² We chose to present the prices in US dollars instead of the local currency, *pesos*. Notwithstanding, we highlight two elements concerning the presentation of these prices in US dollars. First, the prices are disclosed by the Neuquén's province for the wellhead natural gas production being the original data in *pesos* by cubic meter. Second, to make the conversion to US dollars by MBtu, we applied the monthly average exchange rate given by *Ministerio de Hacienda* to provide an annual average. In the next step, we

Figure 28 – Average natural gas prices for the Neuquén region between 1993 and 2019



Source: Neuquén (2020) and Ministério de Hacienda (2020).

Figure 28 shows that between 1993 and 2001, wellhead natural gas prices for the Neuquén region continuously rise from a previous average of US\$ 1 MBtu in 1993 to US\$ 1.6 MBtu in 2001. However, after the 2001 crisis (which will be discussed in the next section) and the reversal of the price liberalization, a substantial fall is followed by a constant price increase, recovering to the 2001 level in 2007. After that point, the price continuously increases until it achieves the record level of US\$ 4.7 MBtu in 2018, falling in 2019 to US\$ 3.5 MBtu (Ministério de Hacienda 2020; Neuquén 2020).

[The 2001 economic crisis reversing the price liberalization process](#)

As several authors affirm, although the economic crisis come to a head in 2001, signs of a crisis are observable from late 1998 (IEO 2003; Fanelli 2003; Lischinsky 2003; Wijnholds 2003; Mussa 2002). The signs are intensified in 2001 with “a sharp and sustained rise in spreads on Argentina bonds over U.S. Treasuries”, demonstrating the market’s identification of a possible default and resulting in higher interest rates for Argentinean bonds. This triggers the International Monetary Fund (IMF) to provide “exceptional financial support” to the government as a mechanism to detain the crisis (IEO 2003, 3–4). Mussa (2002) emphasizes the clear signs of this crisis, classifying the succession of events in Argentina as “the road to catastrophe” (Mussa 2002).

divide the value obtained by 35.3147, resulting on US\$ by thousand cubic feet. Finally, we assume that one thousand cubic feet corresponds to one MBtu (Ministério de Hacienda 2020; Neuquén 2020).

The catastrophe is better exemplified by the social turmoil overtaking the country, which encompasses two presidents' resignations in quick succession and riots that lead to a partial deposit freeze on 1 December 2001. In the aftermath of the deposit freeze, president Fernando de la Rúa resigns on 20 December 2001. To finish the presidential term, on 23 December 2001, congress elects Adolfo Rodríguez Saá. Facing an intensification of the riots, Saá resigns on 30 December 2001. In these circumstances, congress elects Eduardo Duhalde on 30 December 2001, the candidate that lost the 1999 elections against Fernando de la Rúa, to complete the mandate (*The Economist* 2002; IEO 2003, 3–4; Wijnholds 2003, 114–15).

Considering the macroeconomic perspective, we indicate four significant outcomes from this crisis. First, the substantial fall in GDP that continued over two years, achieving -4.4% in 2001 and -11% in 2002, and increased poverty and unemployment (IEO 2003, 17). In 2002, almost half of the population was living in poverty, from less than 28% in 1998 (Fanelli 2003, 33–35), and unemployment reached 18% in 2001 (Wijnholds 2003, 110). Second, facing an overwhelming debt of US\$ 155 billion (around 57% of GDP), the country declared a default in 2001. The default has international repercussions, being classified by *The Economist* as “the largest such default by any country in history” (*The Economist* 2002). Third, national citizens couldn't access their bank accounts, resulting in several riots and leading the country into turmoil (Lischinsky 2003, 91; IEO 2003, 3–7; Wijnholds 2003, 103–7). Fourth, the state abandons the dollar parity, causing a severe devaluation of the national currency (more than 70%). Regarding this aspect, it is relevant to emphasize that the previous plan coping with hyperinflation by guaranteeing a parity between the national currency and the dollar, generating a virtual dollarization of the economy¹⁵³ (Kozulj 2005, 15; Fanelli 2003, 32–33; Lischinsky 2003).

In these circumstances, the government enacts Law 25 561 of 2002 (Emergency law) declaring a public emergency concerning the social, economic, administrative, financial, and exchange rates¹⁵⁴. The Emergency law determines the freezing of public utility tariffs and the

¹⁵³ Concerned with the severe economic depression at the beginning of the 1990s, the government launches the convertibility plan focusing on controlling the hyperinflation adopting almost irreversible measures by law, being the central point the parity between the national currency, *peso*, with the US dollar (IEO 2003, 3). The domestic currency convertibility based on a parity with the US dollar is the leading cause of the 2001 crisis. However, several years of a deficit on both trade balance and government budget associated with a continual reduction in capital flows are other characteristics of the 2001 crisis (Lischinsky 2003, 91; IEO 2003, 3–7).

¹⁵⁴ Despite we quote only the law, there are additional regulations associated with it. In Melgarejo *et al* (2013) words, these additional norms are countless, having as objective “(...) to introduce exceptions to the legal regime in force [of convertibility between *pesos* and US dollar] so as to redirect the sector and mitigate the impact of the regime on users.” (Melgarejo, López, and Montaña Sanz 2013, 48)

dollar's immediate abandonment in favor of the devalued *peso*. Additionally, it also foreshadows the replacement of the US' inflation index with a national one, through the Decrees 645 and 867 of 2002 (Vásquez 2016, 7; Kozulj 2005, 20–25; Fanelli 2003, 32–35; IEO 2003, 3; Argentina 2002a; IAPG 2009, 54).

The implementation of price controls in the natural gas sector to alleviate the social impact of the crisis in Argentina

The amplitude of the 2001 economic crisis forces the Argentinean government to adopt measures to mitigate its consequences. Focusing on the natural gas market, the primary effort is directed to the price control, relieving the population's purchase power deterioration.

Prior to the 2001 crisis, both E&P and natural gas transport and distribution systems have prices in dollars instead of *pesos*. Despite contractual terms guaranteeing price liberty, the emergency law determines a double measure. First, a government control of the wellhead natural gas price (freezing it) and, second, the price's conversion from US dollars to *pesos*.

The transport and distribution systems are subjected to a tariff regulation through a price cap based on dollars and the US' inflation. Thus, as a result of this emergency law, the transport and distribution contracts are renegotiated to incorporate *pesos* and the national inflation index (Vásquez 2016, 7; Kozulj 2005, 20–25; Fanelli 2003, 32–35).

In the E&P sector, the outcome of the Emergency law is a net reduction in natural gas wellhead price around an average of 65% of its previous value in US dollars. From a price varying between US\$ 1 MBtu for fields far from Buenos Aires and US\$ 1.5 per MBtu for fields closest to Buenos Aires, subsequent, to the emergency law, these prices are reduced to US\$ 0.4 MBtu and US\$ 0.55 MBtu, respectively (Kozulj 2005, 41–42). Observing the data for the Neuquén province (shown in Figure 28), from a previous value of US\$ 1.6 MBtu in 2001, it falls to US\$ 0.6 MBtu in 2002, representing a decrease of almost 60% (Ministerio de Hacienda 2020; Neuquén 2020).

Additionally, the emergency law also establishes a tax on O&G exports in the next five years as a means of reducing the government's budgetary deficit. Through the decrees 310 and 809 of 2002, the government determines a 20% tax for oil exports and 5% for oil products and natural gas exports (Argentina 2002a, para. 6; 2002b; 2002c). Despite the prevision to maintain the export duty for five years, the government successively prorogates this duty until 2017 (FARN 2018, 24).

Analyzing the influence of the severe 2001 crisis on natural gas exploration, Honoré (2004) emphasizes the postponement or even the annulation of several E&P projects concerning new

fields and wells drillings. Two measures put in place by private companies demonstrate that point. First, the natural gas offshore field named *Carina*, discovered in 1982, was never developed. Considering the market conditions in 2001, TOTAL (the operator) approved an investment of US\$ 400 million to develop this field. Nonetheless, after the crisis' outbreak, the investment is postponed. Second, drilling to explore natural gas in the country substantially decreases, achieving zero in 2002, merely one in 2003, and 17 in 2004, substantial reductions compared with the record level of 120 in 1999 (Honoré 2004, 17).

Finally, from the household's perspective, as a result of the 2001 crisis, there is a double reduction in purchasing power. Firstly, measured in dollars, the national wages are severely depressed by the national currency's devaluation. Secondly, while there is a reduction in natural gas prices when measured in dollars, measured in the national currency, there is a net increase, from 1.5 *pesos* per MBtu in 2001 to 2 *pesos* per MBtu in 2002 (Neuquén 2020). In these conditions, the government implements a subsidy for natural gas consumption in 2002, which benefits households as well as other natural gas consumers, including industries and power plants (Gomes and Brandt 2016, 27).

On the one hand, a controlled price associated with a direct subsidy enhances natural gas' affordability, increasing its consumption. On the other hand, a controlled wellhead price disregards the side effects in production and reserves. In these circumstances, after the 2001 crisis, the national demand for natural gas increases faster than the output of this fuel, resulting in a supply crisis in 2004 (previously described in section 3.1.1.3).

3.2 The government instruments to mitigate the frontier zone risks of unconventional reservoirs in the Argentinean case

Similarly to the US case, when the Argentinean government faces a supply constraint and external dependence, it applies instruments to raise the national natural gas extraction, resulting in the progressive exploitation of unconventional reservoirs. These initiatives do not explicitly aim to develop unconventional reservoirs, although they enhance the extraction from high-cost regions through two elements: increasing natural gas prices to guarantee the investments' profitability; and accelerating the technological progress undertaken. We emphasize that both elements mitigate frontier risks, being examined through the evolutionary theory and the historical institutionalism, as previously stressed by our analytical framework summarized in Figure 5, chapter 2.

This section aims to analyze the implementation of these instruments that deal with the technological-economic risks represented by three instruments. First, the institutional reorganization of the regulatory framework focused on the liberalization of the price formation mechanism. Second, financial support (through the tax system, subsidies, or others). Third, cooperation between public and private sector. Similarly to the US case, there is a mix among these instruments that stimulate E&P activities, resulting in increased production from unconventional reservoirs.

In the Argentinean case, there is a progressive increase in wellhead natural gas prices associated with a gradual deregulation of price formation. We emphasize that the environment is extremely complex, incorporating a market price control, subsidies for consumers, and higher prices for incremental production. This complex environment inhibits a prompt market liberalization, requiring a schedule to submit consumers and producers with market prices. In these circumstances, the government manages successive schedules to increase prices for natural gas production at the same time that it has been reducing subsidies for consumers, gradually moving the controlled prices to market clearing levels. To unveil the market clearing levels, the government creates an electronic spot market, allowing qualified consumers to directly negotiate natural gas prices.

Our historical-institutionalist analysis of the successive reforms in the regulatory framework of Argentina demonstrates a trajectory leading to the liberalization of the natural gas price (although not yet completed in 2020). Taking a long term perspective, both the US and Argentina proceed with a gradual process of deregulation in price formation. In the US, this trajectory starts in the 1970s, while in Argentina, it begins in the 1980s. Nonetheless, the Argentina particularities (mainly given by the successive economic crises associated with their social repercussions) inhibit a complete price liberalization (which would increase natural gas prices, reducing households' purchasing power).

From the investor's perspective, both countries implemented measures to stimulate additional natural gas production from high-cost regions through financial support, dealing with frontier zones' economic risks. The US implemented a tax credit (from 1980 until 2002) and a price differential (from 1978 until 1993) to stimulate production from new sources. Argentina implemented successive measures to increase wellhead natural gas prices after 2008 (i.e., after the external natural gas dependence in 2007) based on a minimum guaranteed price. Initially, this minimum price is exclusively for additional production. Nonetheless, with the increasing output tendency (which was characterized by declining production from conventional reservoirs

and increasing extractions from unconventional reservoirs), the government re-design the minimum price, focusing on stimulating only the E&P activities in unconventional shale reservoirs.

Comparing the cooperation between the public and private sectors in both cases, Argentina's efforts to accelerate technological adaptation in unconventional reservoirs differs, and is mainly based on two elements. First, the development of unconventional reservoirs is based on the US' experience, which already tested and delimited HF and horizontal drilling as extractive methods of unconventional reservoirs that required substantial efforts from government. Thus, while the US government's efforts focused on encouraging and hosting debates about the most adaptable technological trajectory to develop, Argentina benefited from the previous technological advances made in the US. In these circumstances, the Argentinean technological challenge is centered on adapting these technologies to the local geology. Second, the Argentinean market structure incorporates a NOC, formalizing the government's participation in E&P activities.

Comparing both cases, the US government's cooperation with the private sector is based on creating and subsidizing bridging institutions that are focused on delimiting the challenges of exploiting unconventional reservoirs. This cooperation also focused on R&D support, including operational tests and additional technological development. In Argentina, the government's efforts are limited to its NOC's formal association with private oil companies, and the sharing of development costs through joint-ventures with IOCs and independent companies.

The following section provides more detail concerning the resumption of the regulatory framework's reforms, focusing on the price formation mechanism, the financial support provided, and the cooperation between the NOC and private oil companies.

3.2.1 Shaping a reform trajectory to the liberty of the natural gas price formation

From the government perspective, the lack of both competition and investment in E&P is the primary driver for the 2004 supply crisis, and demands measures to unfold in the short and long term (Kozulj 2005, 30–52; Honoré 2004; Argentina 2004). The long term solution corresponds to a competitive natural gas market in which the price should reflect the market forces between supply and demand. Centered on providing a long-term solution, the government declares its intention to deregulate the price formation, leaving the definition of an equilibrium price to the market dynamic. In these circumstances, the government launches the basis for a spot market - *Mercado Electrónico de Gas* (MEG) – in which the price is defined through

the interaction between supply and demand. The MEG's creation is necessary to completely deregulate natural gas prices in the long term (Argentina 2004, Art. 8).

Additionally, the government allows end-consumers with a demand higher than 10 000 cm³/d to purchase natural gas directly from producers or local distributor (mainly through MEG), being that market completely liberalized since 2005. Nonetheless, there is not yet a forecast for the complete price deregulation for the whole market.

Through the creation of MEG, which is based on the United Kingdom (UK) experience shaping the spot market centered on the National Balancing Point (NBP), the government aims to expose the dynamic between supply and demand that structures the price determination, increasing the price formation's transparency. Additionally, we highlight that the government formalizes the liberty for the price formation through MEG (committing to not control these prices), showing its interest in providing more security for agents trading in this spot market (Secretaría de Energía 2004, 5–12). MEG is an association between the Argentinean government and the Buenos Aires stock exchange that is formalized through decree 180. It has the main objective of coordinating supply and demand in the natural gas market, disclosing the price formation. This market price is entirely based on market fundamentals concerning commercial and physical transactions, particularly the spot value for the molecule and its transport costs, being a fundamental step to achieving higher levels of competition and price formation transparency.

[The subsidies for natural gas consumers in Argentina](#)

A constraint of price liberalization is the government's subsidies, which limit the supply and demand responses to price signals. Since the economic crisis of 2001, the government has been subsidizing natural gas prices for consumers. Since the 2004 supply crisis, the government has been scheduled to end these subsidies, successively postponing the date to end them.

After the supply crisis in 2004, a measure for restraint demand is to reduce the consumers' subsidies progressively. From this perspective, the government program to finally terminate the natural gas subsidies in 2006, gradually increasing natural gas prices for all consumers (including industries, power stations, commerces, and households¹⁵⁵). Thus, it schedules four price

¹⁵⁵ These price increases for consumers are based on resolutions 180 and 181. These resolutions divided the market by regions and kind of consumers splitting the increase in prices according with the consumer categories aiming a total realignment until 2006. In order to achieve this price increase, industries, power plants and vehicular gas users (near 80% of the whole demand) observed a price increase divided on four phases. The first starting in March 2004 and the last in July 2005. For household's consumers, the price

increases between 2004 and 2006, forecasting that in 2006 all consumer categories will achieve a single price, allowing for market liberalization. Despite the progressive price increase for industries, in 2006, the government keeps subsidizing the generation of electric power and the households' consumption.

In 2015 the government schedules another progressive reduction in subsidies, planning to shift from a linear subsidy for all households to an income transfer program. This plan consists of two phases. In the first phase, the government limits the subsidies to only the most vulnerable populations, creating the program *Tarifa Social Federal*, which reduces the natural gas prices for the most vulnerable. In the second phase, the government aims to convert this subsidy program to an income transfer program, eliminating the natural gas price subsidy. This conversion aims to end the natural gas price distortions facing consumers with the market price and, simultaneously, to redistribute income for the most vulnerable households as a mechanism to alleviate the burden of higher natural gas prices (Secretaría de Gobierno de Energía 2019b, 10–20; Natale 2019; Chambouleyron and Ferraris 2018; Einstoss 2017).

Effectively, the government reduces the total expenditures from natural gas subsidies from 1.4% of GDP in 2014 to 0.5% of GDP in 2019. The principal reduction is proportionated by the decrease in subsidies for power plants. Nonetheless, in 2019 the average subsidies for households are around 46% of the total natural gas price. Additionally, there is not a forecast to convert the subsidy to an income transfer program. The association of these elements demonstrates the difficult task of ending the natural gas prices subsidies, postponing the complete market's deregulation (Secretaría de Gobierno de Energía 2019b, 10–20; Natale 2019).

3.2.2 Beyond the liberalization process, an increase in wellhead natural gas prices to stimulate production: the three gas plans

The government launches three plans since 2008¹⁵⁶ that guarantee a minimum price for the natural gas produced nationally. The government has two objectives with these plans. First, to reduce the external natural gas dependence. Second, to reduce the government expense of subsidies for consumers. These objectives are achieved by increasing wellhead natural gas prices, encouraging E&P activities and national production. The increase in national production

realignment is schedule to happen in December 2006 (Kozulj 2005, 30-32;40-41,52; Honoré 2004, 26; Secretaría de Gobierno de Energía 2019b, 3–5).

¹⁵⁶ There is a proposition to redesign the last plan (Gas III by Gas IV) aiming to limit the government expenses (officially the plan is named “Estímulo a la Producción de Gas Natural” however is treated as Plan Gas IV).

reduces the necessity of imports, and, consequently, the external natural gas dependence. The initial imports to be reduced are the most expensive, and, in the Argentinean context, these are LNG imports. Thus, from the government’s perspective, the increase in national wellhead natural gas prices replaces the subsidy for LNG imports, reducing the national supply's total subsidies.

A summary of this financial support offered (through a minimum price) for the national production is provided in Table 8, below. The table shows the average price for the Neuquén region and the higher wellhead natural gas price according to each plan.

Table 8 –Price differential in Argentina between 2008 and 2021

Years	Wellhead average price (US\$ MBtu)		Price differential	Plan	Price differential to:
	Neuquén	Plan			
2008	2.3	4.1*	79%	Gas Plus	additional production from all reservoirs
2009	2.2	4.69*	110%		
2010	2.4	4.89*	101%		
2011	2.7	5.2*	90%		
2012	2.6	5.09*	97%		
2013	2.6	5.18*	101%		
2014	2.7	7.5	173%	Gas I and II	additional production from all reservoirs
2015	2.6	7.5	190%		
2016	3.3	7.5	129%		
2017	4.1	7.5	83%		
2018	4.7	7.5	59%	Gas III	only unconventional reservoirs can apply
2019	3.5	7.0	102%		
2020	2.4**	6.5	171%		
2021		6.0			

*estimations.

** average price until June 2020.

Source: Gomes and Brandt (2016, 29–30), Bravo (2015, 23), Argentina (2008; 2013), Ministério de Hacienda (2020) and, Neuquén (2020).

Observing the plan’s objectives and the national production values since 2008 (visible in section 3.1.1.1 and Figure 24), we conclude that the plans have been achieving their goal, which is mainly based on three elements. First, national production has been rebounding since 2014. Second, national production has been replacing the most expensive LNG imports, and consequently, the government has been reducing the expense of natural gas subsidies. Third, the production from unconventional shale reservoirs has been growing since plan Gas III (when the government focuses the price stimulus only for these reservoirs).

The following subsection provides more detail about the minimum price created by these three plans, and is shared in three parts. The first presents the plan Gas Plus that focuses on recovering the national production of natural gas. The second describes the re-design of this initial plan, which mainly clarifies the wellhead price for additional production, named plans Gas I and II. The third gives an overview of the additional refinements aimed at focusing the higher wellhead natural gas prices only for unconventional shale reservoirs, the plan Gas III.

3.2.2.1 The plan Gas Plus aiming to recover the national production

After the period of external natural gas dependence began in 2007 (detailed in section 3.1.1.3), the government launches the plan Gas Plus in 2008, focusing on increasing E&P activities to raise national natural gas production. The plan takes as its goal increasing both production and reserves by stimulating E&P activities in new natural gas areas. Despite the government's objective of recovering the national production of natural gas, the plan does not achieve its purpose, and is re-designed in 2013.

This 2008 plan, Gas Plus, establishes a higher wellhead natural gas price for extractions from new reservoirs never exploited or already discovered, stimulating the E&P activities in the hard-to-reach natural gas reserves of unconventional reservoirs. On the one hand, the program focuses on increasing national production, providing a price stimulus to encourage E&P activities. On the other hand, the value of the wellhead natural gas price is highly subjective. To clarify, the plan declares that producers will receive a price corresponding to the operational costs, plus a reasonable profit for the additional natural gas output. While there are fewer problems with the operational cost definition, the term 'reasonable profit' adds uncertainty to the final wellhead price (Argentina 2008; USA 2015, 65).

Gomes and Brandt (2016) estimate that, under the Gas Plus program, wellhead natural gas prices in Neuquén more than double from the previous value. According to the authors, the plan increases wellhead natural gas prices to a maximum of US\$ 5.2 MBtu (Gomes and Brandt 2016, 29). Another estimation for the price differential is provided by Bravo (2015), who affirms that the minimum price is close to US\$ 4 MBtu and never exceeds US\$ 7.5 MBtu (Bravo 2015, 23). Based on these estimations associated with wellhead natural gas prices for the Neuquén region, we provide our estimation, detailed in Table 8.

However, from the investors' perspective, this price stimulus is opaque, since it is based on such subjective parameters as each field's particular features (calculated considering the overall costs) and associated with an estimation of a 'reasonable profit'. This opacity in price

formation is strongly criticized by producers, leading the government to re-design this plan in 2013 to focus on higher transparency and values.

3.2.2.2 The plans Gas I and II

Facing the decreasing national production, the government redesigns the plan in January 2013, mainly focusing on offering more transparency and even higher wellhead natural gas prices through two plans, Gas I and Gas II¹⁵⁷. Concisely, the plan Gas I increases the wellhead natural gas price for any growth considering the current production levels, and the plan Gas II focus on providing this price increase for small producers (even considering the possibility of maintaining the current production level). Both programs define a fixed price of US\$ 7.5 MBtu¹⁵⁸.

The plan focuses on increasing wellhead natural gas prices and providing transparency in the price formation in order to stimulate E&P investments. Concerning the price increase, from a previous price that was based on operational costs combined with a reasonable profit, the government sets a minimum price for the additional production of US\$ 7.5 MBtu, paying to producers the difference of the market price. From the government perspective, this expense is lower than the that of LNG imports (which ranges between US\$ 12 MBtu and US\$ 15 MBtu according to Bravo (2015, 23)) while from the investor perspective, it represents a substantial increase from the previous value applied by plan Gas (an average of US\$ 4.8 MBtu).

The plan defines that any additional natural gas production could apply to receive the minimum price. For this, the government initially split E&P projects on new and existent. Investments in new areas could apply for the minimum price, because, in the government perspective, the new production is incremental, rising the national production levels. Thus, the investment in new areas may apply for the minimum price.

Investments in fields producing. i.e., investments in revitalizing the output of production areas, may also apply for the minimum price. However, previously, the government had established a production curve (acting as a measure of the target production) and, if the

¹⁵⁷ The plan Gas I is implemented by the *Comisión de Planificación y Coordinación Estratégica del Plan Nacional de Inversiones Hidrocarburíferas* through the Resolution 1 of 18 January 2013. The plan Gas II is implemented by the same commission through the Resolution 60 of 8 November 2013, defining as small producer the company with a total natural gas injection in the transport system inferior to 3.5 Mcm/d (Secretaría de Gobierno de Energía 2019a, 4–5; Argentina 2013).

¹⁵⁸ After the plan Gas I and II, the government launches other incentives encouraging the private investment, among them we quote two. First, through the decree 929/2013 of July 2013, investments higher than US\$ 1 billion may export 20% of the production after five years of the production begin without the exportation duty. Second, through law 27.007 of 2014, the government simplifies environmental norms relating to the E&P activities on unconventional reservoirs (Ceppi 2018, 54).

producer overcomes the production curve, this supplementary production may apply for the minimum natural gas price (Secretaría de Gobierno de Energía 2019a, 4–5; Argentina 2013, 1–2).

From the investor perspective, instead of receiving market prices, any producer developing a new reservoir or increasing its production beyond the curve delimited will receive US\$ 7.5 MBtu. Thus, there is a notable improvement in the transparency surrounding this incentive when compared with the previous plan. Additionally, over the plan's duration, between 2013 and 2018, this price stimulus results in average price that is 144% higher than the market price, as shown in Table 8. This price stimulus is sizable enough to increase E&P activities and Argentine national production.

3.2.2.3 The plan Gas III focusing efforts on accelerating the development of unconventional reservoirs

In 2018, the government takes two measures reflecting its efforts to ramp up the natural gas supply growth. First, it allows natural gas exports in the summer season¹⁵⁹. Second, it refines the existing plan, replacing it with plan Gas III. The plan Gas III reformulates the incentives for natural gas production, focusing solely on unconventional reservoirs.

The plan Gas III differs from the previous in three main elements. First, it disregards conventional production, focusing on accelerating the unconventional reservoirs' development, mainly those richer in oil such as those of the *vaca muerta* formation (shale formations). In practice, only unconventional shale reservoirs have their plans approved by the government. Second, a field's entire production can demand a higher price, as opposed to the stipulation of the previous plans that limited their applicability to a field's additional output. In other words, there is no differentiation between new or existent fields. Third, it forecasts a decline in the wellhead natural gas price, instead of the previous plan fixing it indefinitely at US\$ 7.5 MBtu. Thus, this plan is the first to forecast a progressive reduction in the minimum guaranteed price, gradually moving wellhead prices to market levels (Secretaría de Gobierno de Energía 2019a, 5; FARN 2018, 21–22).

¹⁵⁹ The exports are allowed by Resolution 104 of 2018. In this circumstances, the companies resume the exports to Chile, achieving a peak of 9.1 Mcm/d in February 2019 (Secretaría de Gobierno de Energía 2019, 5).

According to plan Gas III, all production from unconventional reservoirs in the Neuquén Basin could apply for the minimum wellhead natural gas price¹⁶⁰. The plan forecasts a minimum price of US\$ 7.5 MBtu in 2018, reducing the rate by US\$ 0.5 MBtu per year until it achieves the value of US\$ 6 MBtu in 2021. Additionally, it forecasts that, after 2021, production from unconventional reservoirs will receive the market price¹⁶¹ (Argentina 2017). Considering the market prices between 2018 and 2020 (with data until June 2020), this price stimulus represented an average value 110% higher than the market price, as demonstrated by Table 8.

3.2.3 The re-organization in the E&P market focused on the YPF re-nationalization

From the government perspective, the main political justification for the supply crisis is the market organization without the state presence, providing the necessity of re-nationalizing YPF (the formal NOC) to increase control in the E&P sector and, subsequently, raise E&P investments. Despite this reorganization, the previous structure based on private participation in both the transport and distribution systems remains.

Law 26 741 of 2012 declares the nationalization of YPF, expropriating¹⁶² the Repsol company¹⁶³. The main argument justifying this initiative is to raise E&P investments, recovering the previous production levels, in other terms, reducing the country's external dependence (Argentina 2012, para. 1; Bravo 2015, 24–35).

Notwithstanding the declared government objective of the expropriation, the Repsol chairman declares that this government measure aims to “control the discovery of vast deposits of unconventional hydrocarbons in Vaca Muerta, made by Repsol-YPF of which a small part has been audited and valued at more than 13.7 billion dollars” (Melgarejo, López, and Montaña Sanz

¹⁶⁰ The initial resolution restrains the minimal price to the Neuquén Basin. However, the resolution 447 of 2017 allows unconventional reservoirs of the Austral Basin to be incorporated to this plan.

¹⁶¹ In October 2020 the government outlooks to replace plan Gas III by plan Gas IV. According to *Instituto Argentino de la Energía* (IAE) the government aims a double objective. First, limit the total production that could receive the price stimulus to 70 Mcm/d. Second, change the price stimulus in 2021 from US\$ 6 MBtu to US\$ 3.4 MBtu. To compensate the price decrease, the government outlooks to keep the price stimulus until 2024 (IAE 2020).

¹⁶² Melgarejo *et al* (2013) declare that the expropriation is expected since the government has been increasing their nationalistic arguments waiting for the moment to launch the YPF expropriation. The successive nationalization of several companies demonstrates this point. This movement starts in March 2006 with the nationalization of the water distribution and treatment company in Buenos Aires, Aguas Argentinas. In 2008 the government expropriates the private pension funds AFJP and the Aerolíneas Argentinas (Melgarejo, López, and Montaña Sanz 2013, 45).

¹⁶³ Although we quoted only the Repsol company, previous to the nationalization, the YPF shares are distributed among several companies, the biggest being Repsol (58.23%) and the Petersen Group (25.46%) (Melgarejo, López, and Montaña Sanz 2013, 48–49; Bravo 2015, 30).

2013, 54). Prior to the expropriation, the Repsol chairman proposes to the Argentinean president a joint investment that will increase oil production by 30% and gas production by 20% in five years, reducing the country's energy dependence and resuming hydrocarbon exports (Melgarejo, López, and Montaña Sanz 2013, 54). Additionally, Bravo (2015) criticizes the absence of a previous energy plan delimiting the government's goals with the expropriation, which demonstrates the government's political targets instead of energy goals (Bravo 2015, 30).

3.2.3.1 State companies coordinating the E&P investments in unconventional reservoirs through formal partnerships with the private sector

Despite the re-nationalization of YPF, this company retained and expanded its partnerships with private companies, mainly IOCs. These formal partnerships focused on developing unconventional shale reservoirs of *Vaca Muerta*, delimiting the cooperation between the public and private sectors through the Argentinean NOC. Additionally, the provincial government of the Neuquén province also creates its own company to accelerate the development of unconventional reservoirs through joint ventures. Thus, we conclude in the governmental cooperation with private companies sharing development costs through formal partnerships.

YPF has been classifying these partnerships as strategic, focusing on accelerating the exploitation of unconventional shale reservoirs of *Vaca Muerta*. These partnerships seek to develop the necessary infrastructure to proceed with HF and horizontal wells, sharing technological risks with private companies. Additionally, these partnerships also allow the NOC to access the relevant know-how provided by companies involved in the US shale development. Table 9, below, lists the main YPF partnerships with private companies in the *Vaca Muerta* region.

Table 9 – YPF’s main partnerships with private companies in the *Vaca Muerta* region

Company	Field	Participation	Company type
Shell	Bajada de Abelo	50%	IOC
TOTAL	San Roque	25%	IOC
	Cerro las Minas	50%	
	Ag. De Castro	50%	
	Ag. Pichana Este	40%	
	Ag. Pichana Oeste	25%	
Equinor	Bajo del Toro	50%	NOC
Wintershall	San Roque	25%	independent
	Ag. Pichana Este	23%	
PAE*	San Roque	16%	IOC
	Lindero Atravesado	62%	
	Ag. Pichana Oeste	45%	
	Ag. Pichana Este	15%	
Petronas	La Amarga Chica	50%	NOC
Chevron	Loma Campana	50%	IOC
Pluspetrol	M. Buena	50%	independent
	Esperanza		
	La Calera		
	Las Tacanas		
DOW	El Orejano	50%	independent
Chevron	Loma Campana	50%	IOC
	Narambuena	50%	

*Pan American Energy, a joint venture between BP and Axion.

Source: YPF (2019; 2014) and Lopetegui (2019).

Remarkably, the central partnerships of YPF are with international IOCs. From this list, only a single company is a national independent company, Pluspetrol.

Additionally, to raise investments in unconventional reservoirs of *Vaca Muerta* region, in 2008, the provincial government of Neuquén creates Gas y Petroléo Neuquén (GyP), allocating exploratory rights to this company. GyP has the objective of directly exploring these areas or seeking private companies to share the exploration rights. Since 2009, this company has signed 58 exploratory contracts, of which 36 are active with relevant joint-ventures with IOCs and independent companies. The most relevant joint ventures signed by GyP are shown in Table 10, below.

Table 10 – GyP’s main partnerships with private companies in the *Vaca Muerta* region

Company	Field	Company type
Shell	Sierra Blancas Cruz de Lorena Rincón la Ceniza La Escalonada	IOC
TOTAL	Rincón la Ceniza La Escalonada	IOC
Exxon	Los toldos 1 Sur La Invernada Bajo del Choique	IOC
Wintershall	Aguada Federal	independent
XTO energy	La Invernada Bajo del Choique Los toldos 1 Sur	independent
Tecpetrol	Los toldos 1 Sur	independent

Source: Lopetegui (2019).

Concerning the partnerships of GyP, we highlight that the majority of the joint-ventures are with IOCs (Shell, TOTAL, and Exxon) and independent companies (Wintershall and XTO energy). The last company, XTO Energy, is an independent company with a strong actuation in the US’ unconventional shale reservoirs. Finally, the single national company in partnership with GyP is Tecpetrol.

3.3 An analysis of the learning curve and the market structure in the *Vaca Muerta* region

Concerning the acceleration in the technological adaptation, the Argentinean case proves the arguments previously emphasized by several authors, that the development in the US enhances the technological adaptations in other countries, reducing the necessary time to appropriate gains from the learning curve (Wang and Krupnick 2013; Anderson 2013; Stevens 2010). Comparing both cases, it is clear that the US’ technological adaptation demands more time (starting in the 1970s, with a significant increase in output from the Barnett shale region in the 2000s) than the Argentinean case (starting in the 2000s with increased production in the *Vaca Muerta* region in the 2010s).

Considering technological development, the US has to delimit and encourage tests with HF and horizontal drilling in order to validate these methods’ technical and economic viability. In contrast, Argentina encourages producers to engage the regional learning curve to appropriate the gains derived from technological adaptation, having as an example the US case.

In more detail, in the US, there is a proliferation of incentives to accelerate technological progress (tax credits, higher natural gas prices, the creation of bridging organizations to encourage R&D). In Argentina, the primary incentive is a minimum price guaranteed by the state associated with formal cooperation with its NOC.

Assessing the *Vaca Muerta* case using the evolutionary theory (summarized by Figure 5 in chapter 2) demands the analysis of two mechanisms dealing with technological risks: its regional learning curve and the risk aversion of companies operating in the *Vaca Muerta* area. Our analysis of the learning curve shares it in two stages in the *Vaca Muerta* case. As previously identified in the Barnett shale case, the first stage corresponds to the introduction of HF method in the region, while the second encompasses the association of HF and horizontal wells on unconventional shale reservoirs.

However, investigating the market structure we find some similarities and divergences between the cases. In both cases, in the first stage, there is an independent company leading the regional production. In the second stage, a bigger company merges operations with the leading company, driving the second learning curve stage associating HF with horizontal drilling. Nonetheless, this new leading company is independent in the US case, while in Argentina, it is the home NOC. Finally, we emphasize that in the analysis of the US case, the IOCs do not participate of this process (the movement of IOCs consolidating several US shale areas are more recent than our temporal analysis of the Barnett shale case), while in the Argentinean case, they participate in both learning curve stages.

Another remarkable difference is linked with a *Vaca Muerta* feature, a region hosting two kinds of unconventional reservoirs in the same area, tight and shale. The existence of these reservoirs allow operators to share the stages of the learning curve by reservoirs. In this case, the adaptation of HF to the local geological context is made by exploiting unconventional tight reservoirs. Tight reservoirs could be commercially exploited through vertical wells, while the commercial exploitation of shale reservoirs demands the association between horizontal drilling and HF in the *Vaca Muerta* case¹⁶⁴ (Mayol 2019, 2–3). In this case, unconventional tight reservoirs in *Vaca Muerta* enable HF adaptation (and all their necessary infrastructure) before exploiting the vastest and richer shale reservoirs.

¹⁶⁴ Mayol (2019) affirms that the early exploration of the shale unconventional reservoirs is based on vertical wells. More precisely, between 2011 and 2014, after 414 wells to evaluate this formation, several operators concluded that its exploration through vertical wells are uneconomic (Mayol 2019, 2–3).

Finally, we recall that we define independent companies by their lower risk aversion (when compared to other companies) in chapter two, disregarding IOCs and NOCs since they are absent from the Barnett shale. According to Al-Fattah (2013), the classification among these firms incorporates several dimensions being, one of them, their risk aversion. In these circumstances, the definition of a company as independent, IOC or NOC also reveal their risk' aversion, shaping a profile of the companies involved in the technological adaptation in the area.

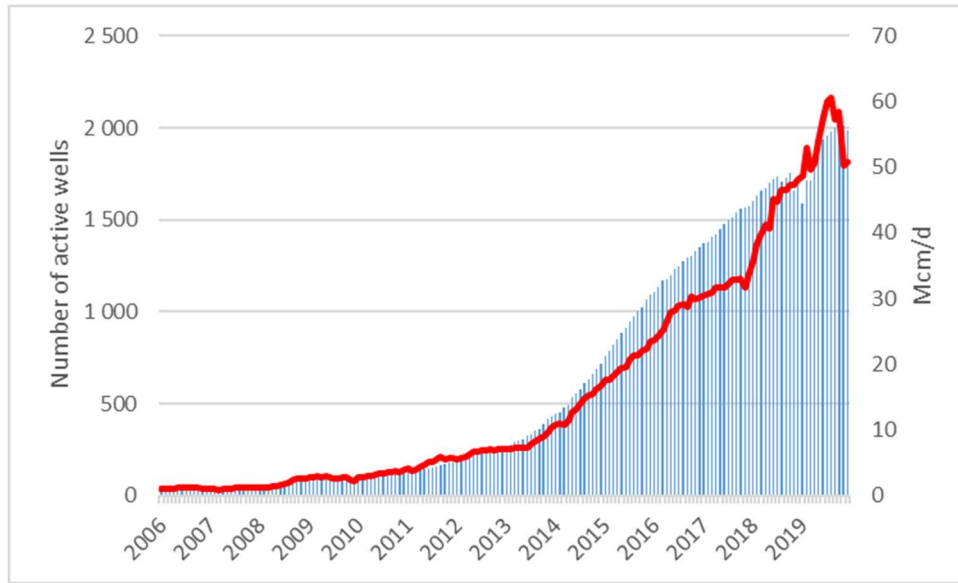
IOCs also could be called integrated oil companies, in direct opposition to the independent companies, because of its business operations across all the O&G sectors. Their main feature is its vertical integration, operating in the whole supply chain encompassing exploration, extraction, transportation, storage, and marketing of crude and refined oil (Al-Fattah 2013, 4). Concerning its risk aversion, as Ledesma (2009) emphasized, these companies are driven by the shareholder value's maximization limiting its risks appetite to some operations. Thus, these companies focus on providing the necessary funds to develop massive O&G projects, mainly with technologies already proved as technical and economical viables, limiting its risks exposure to some specific projects. In these circumstances, IOCs are primarily involved in projects demanding considerable investments, searching for partnerships to share the project's risks and, diversifying its assets to achieve higher shareholder values (Al-Fattah 2013, 4; Ledesma 2009, 19–21).

NOCs represent companies controlled by their governments with assets and business focused on their home country, independently of their central investment destination (that could be predominantly international). These companies depend on government decisions concerning their risk aversion, varying according to each country and specific operation. Thus, when NOCs operates internationally, their risk aversion can swing between IOCs or independent companies (Al-Fattah 2013, 2; Ledesma 2009, 5). The following section provides more details about our analysis concerning the two learning curve stages for the *Vaca Muerta* case.

3.3.1 The three wells' productivity peaks

Analyzing the number of active wells associated with production from the *Vaca Muerta* region, we observe a progressive increase in both E&P indicators (active wells and total production from unconventional reservoirs). Figure 29, below, shows them between 2006 (the first data available for the region's production considering individual wells) and 2019 (the last complete data).

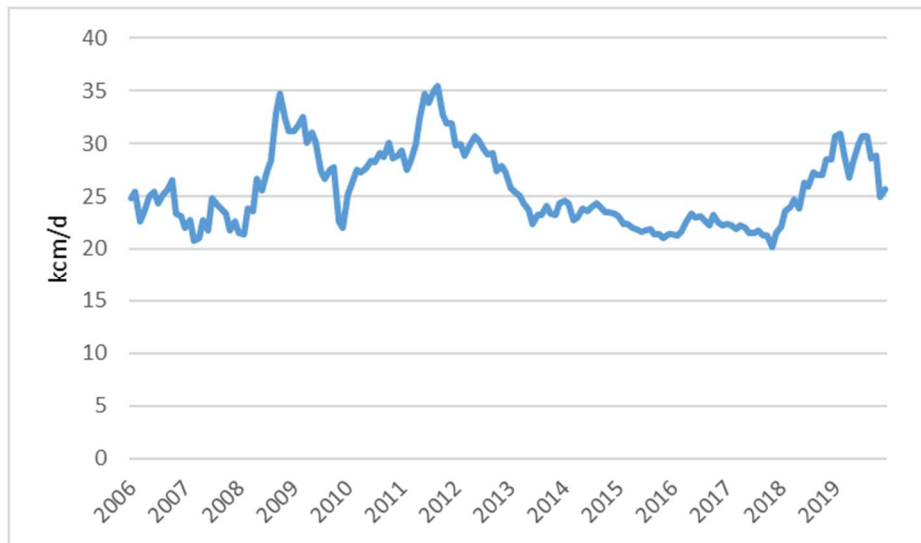
Figure 29 – Number of active wells and natural gas production from unconventional reservoirs in the *Vaca Muerta* region



Source: Based on Secretaría de Energía (2020b).

In Figure 29, the red line represents the production from unconventional reservoirs in the *Vaca Muerta* region (on the right scale), while the blue columns represent the total active wells (on the left scale). Until 2019, the *Vaca Muerta* E&P indicators are similar to the Barnett shale case, presenting a continuous increase in active wells associated with a progressive increase in regional production. Nevertheless, since 2019 there is a reduction in both indicators (active wells and total production from unconventional reservoirs) in the *Vaca Muerta* region, mainly given by the uncertainty about the country’s economic perspectives. To capture the relationship between these indicators, we calculate the well’s productivity. Figure 30, below, shows the average well’s productivity of unconventional reservoirs in the *Vaca Muerta* region, identifying three well’s productivity peaks.

Figure 30 – Average wells' productivity in the *Vaca Muerta* region



Source: Based on Secretaría de Energía (2020b).

Figure 30 shows that the first well's productivity peak occurs in 2008, the second starts in 2010, and the third beginning in 2018. At first glance, we identify that the wells' productivity averages 25 thousand cubic meters per day (kcm/d). The first two productivity peaks attain levels close to 35 kcm/d, and the third reaches values close to 30 kcm/d.

In more detail, the first encompasses a few months of 2008, starting in June 2008 until it achieves the productivity peak of 35.1 kcm/d in September 2008, when it returns smoothly to its previous average. The second lasts almost two years, between 2010 and 2011, being featured by a gradual increase starting in 2010 with a peak in 2011, achieving 35.7 kcm/d in September 2011. Finally, the third represents a gain in productivity since July 2018 with two peaks in 2019 when it reaches 30 kcm/d.

Additionally, since 2008 the natural gas prices has been increasing due to the government plans guaranteeing a minimum wellhead natural gas prices. In these circumstances, the productivity peaks signalize relevant moments to be investigated concerning the technological achievements, leading our analysis of the learning curve considering its stages and the market structure.

The following section examines these three well's productivity peaks in more detail, identifying the learning curve stages.

3.3.2 The first learning curve stage as a consequence of the minimum natural gas price

Comparing the first learning curve stage in the *Vaca Muerta* with the US Barnett case, we identified similarities and differences. Different from the US Barnett shale experience, the

leadership in the *Vaca Muerta* case is more fragile. More precisely, Mitchell Energy keeps its leading role hovering around 85% between 1993 and 1999, while in Argentina, the leading company never exceeds 60% of participation in the first learning curve stage.

Similarly from the first learning curve stage in the US Barnett shale case, companies in *Vaca Muerta* focused on reducing the operational costs. In the US case, Mitchell Energy executed several tests through a trial-and-error aiming to increase the well's productivity and, consequently, reduce costs. In Argentina, operators focused the E&P activities on unconventional tight reservoirs through vertical wells. The commercial exploitation of unconventional shale reservoirs in the *Vaca Muerta* region demands the association between HF and horizontal drilling, while in unconventional tight reservoirs, it could be made using HF through vertical wells, notably less expensive than horizontal ones.

Finally, another remarkable similarity is independent companies leading the first learning curve stages in both countries. Between 2006 and 2011, the leading role (despite a share of around 55%) is rolled by independents companies, until 2006 by Capex and between 2007 and 2011 by Apache. While the first is an independent national company, the second is a US independent company from Texas. We highlight that in the *Vaca Muerta* case, the leading role is more precarious than in the US case since it is based on lower levels of both active wells and production.

The analysis of the E&P indicators associated with the market structure (encompassing the companies operating in this area, their type and market share) in the productivity peaks of 2008 and 2011 allows us to reach three conclusions related to the first learning curve stage. First, operators focus on unconventional tight reservoirs, notably less expensive to develop than the shale reservoirs. Second, the investment directed to the *Vaca Muerta* region remarkably accelerates after the implementation of the plan Gas Plus in March 2008 (i.e., after the government guarantees the minimum wellhead natural gas prices, as previously shown in Table 8). Third, there is a progressive increase in operators interested in exploiting these resources, encompassing IOCs, independents, and NOC.

3.3.2.1 The E&P indicators of the first productivity peak

Both indicators, the active wells and the average well's productivity increase in 2008, being associated with the implementation of the plan Gas Plus after March 2008. Taking March 2008 as the reference point, new active wells' addition achieves 19 between March and September 2008. Compared with the previous values (addition of 7 wells in 2006 and 5 in 2007), it substantially increased (Secretaría de Energía 2020b).

Analyzing the average well's productivity considering only unconventional shale reservoirs (the *vaca muerta* formation), it reaches 0.9 kcm/d in March 2008 while in unconventional tight reservoirs, it reaches 25.2 kcm/d. In September, these numbers rise to 7.4 kcm/d and 34.8 kcm/d, respectively. Considering the active wells, while the shale reservoirs increase from 3 to 4, the tight reservoirs increase from 52 to 70 (Secretaría de Energía 2020b). We conclude that companies centered E&P activity on the most productive unconventional tight reservoirs¹⁶⁵.

3.3.2.2 The E&P indicators of the second productivity peak

The second productivity peak is a continuity of the 2008's peak, being associated with an expansion in E&P activities. The productivity gain is mainly due to the focus on unconventional tight reservoirs. This dynamic reveals a continuity of the learning curve from the HF method's introduction in these reservoirs.

In this period, the active wells also accelerate, achieving 31 additional wells in 2010 and 43 in 2011. The majority of these new wells focused on extracting natural gas from unconventional tight reservoirs¹⁶⁶. Considering the well's productivity, it continuously increases in unconventional tight reservoirs from an average of 26.2 kcm/d in 2010 to 36.2 kcm/d in 2011 while unconventional shale reservoirs decrease its average well's productivity from 7.9 kcm/d to 5 kcm/d¹⁶⁷ (Secretaría de Energía 2020b).

Differently from the shale formations of *vaca muerta* requiring the association of horizontal wells with the HF method, producers could commercially exploit tight formations associating HF method in vertical wells, guaranteeing lower exploitation costs¹⁶⁸ (Sbroiavacca 2013, 11; Mayol 2019). In this case, tight reservoirs present lower costs, given the possibility to

¹⁶⁵ Mainly in the *precuyo* and the *lajas* formations, the most productive tight formations. While the average well's productivity of the first tight formation increases from a previous average of 40 kcm/d to a peak of more than 80 kcm/d, the second tight formation increases its average productivity from 20 kcm/d to almost 40 kcm/d.

¹⁶⁶ Sharing the data considering the tight or shale reservoirs, while the first adds 27 new wells the second adds only 4 in 2010, in 2011 the tight reservoirs adds another 28 new active wells while the shale reservoirs increases 15 new active wells (Secretaría de Energía 2020b).

¹⁶⁷ The main unconventional tight reservoirs responsible by increasing the well's productivity are the *lajas* and *mulinchinco* formations. While the first increases its average productivity from 16 kcm/d to more than 30 kcm/d, the second increases from 24 kcm/d to more than 60 kcm/d. Both formations also increased the quantity of active wells, the *lajas* formation from 19 in January 2010 to 46 in December 2011 while the *mulinchinco* formation increased from 8 to 16 in the same period (Secretaría de Energía 2020b).

¹⁶⁸ Similarly of the Barnett shale case, HF method are not new, being used for the first time in Argentina in the 1960s. However, its wide application starts after the implementation of the plan Gas Plus, generating the necessary prices to expand the exploitation of unconventional reservoirs (Bonapace 2015).

quickly increase the natural gas production utilizing vertical wells instead of the most expensive horizontal ones demanded by shale reservoirs. This element allows an increase in HF operations in the region, creating the necessary infrastructure for operations.

The official data corroborates this explanation. Comparing the average horizontal distance from wells drilled on tight and shale formations in the *Vaca Muerta* region, the horizontal distance is higher on shale formations. In more detail, tight reservoirs achieve an average horizontal distance between 2011 (the first year of the dataset) and 2019 (the last year) of 129 meters (m) while shale reservoirs achieve an average horizontal distance of 936 m in the same period (Secretaría de Energía 2020a).

3.3.2.3 The market structure and the leading role in the first learning curve stage

Taking as a metric the output in unconventional reservoirs, since 2006, Capex, an independent company from Argentina, is the leader of this market with total production from unconventional reservoirs achieving 0.6 Mcm/d in 2007 from 23 active wells. This production is enough to guarantee a share of 52% in the *Vaca Muerta* region, as shown in Table 11, below.

Table 11 – Market share in production from *Vaca Muerta* region between 2007 and 2011

Companies	2007	2008	2009	2010	2011	Company type
APACHE	3.4%	32.1%	55.5%	54.2%	56.4%	independent
PETROBRAS ARGENTINA	20.9%	22.3%	14.5%	22.9%	23.6%	NOC
CAPEX	52.6%	28.2%	16.4%	10.7%	5.9%	independent
YPF*	13.1%	11.6%	9.7%	7.0%	4.8%	IOC*
TOTAL	0%	0%	0%	1.3%	3.8%	IOC
PLUSPETROL	0.3%	0.2%	0.1%	1.6%	3.8%	independent
CHEVRON	5.9%	3.0%	2.1%	1.2%	1.0%	IOC
PAE	2.7%	2.1%	1.3%	0.7%	0.4%	IOC
TECPETROL	1.0%	0.5%	0.4%	0.3%	0.2%	independent
Others Companies (<0.5%)	0%	0.1%	0.1%	0.1%	0.1%	-

*YPF is re-nationalized in 2012.

Source: Based on Secretaría de Energía (2020b).

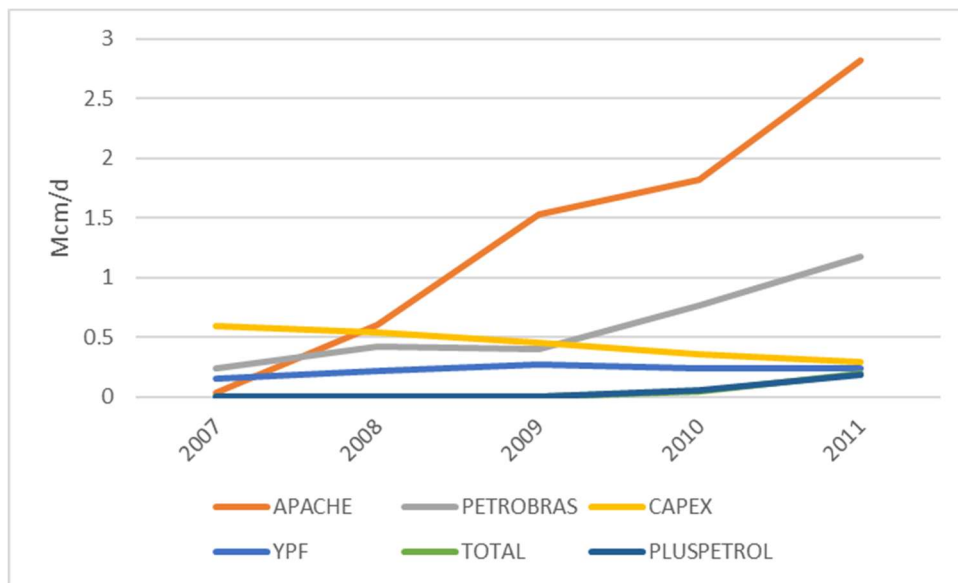
Capex's leadership is quickly surpassed by Apache, an independent US company based in Houston, Texas. Apache has been applying both extractive methods, HF and horizontal drilling, in US and Canadian Basins hosting unconventional reservoirs (as the Permian Basin of West Texas and New Mexico). Concerning its international investments, the company also devoted efforts to developing unconventional reservoirs in Egypt's Western Desert Basin. Finally, Apache structured its operations considering the necessity of introducing continuous innovations to adapt the technology to the local context, appropriating gains from the regional learning curve through a constant cost reduction that enhances the operational efficiency (C. Cooper 2011, 2).

Apache substantially increases its drilling on unconventional tight reservoirs after the implementation of the plan Gas Plus (March 2008). The company increases its active wells from 2 in February 2008 to 24 in December 2008, keeping its expansion to 44 in December 2009 and 66 in December 2010. This investment is more than enough to overcome the Capex leadership in 2008 when Apache achieves 32% (meaning a total production of 0.6 Mcm/d), and Capex falls to 28% (0.5 Mcm/d), as shown in Table 11.

According to Secretaría de Energía (2020b), between 2007 and 2011, eleven companies operating in the *Vaca Muerta* region applied to participate in the plan Gas Plus (that guarantees the minimum price for natural gas as previously explained in Table 8) (Secretaría de Energía 2020b). From these companies, only nine produced between 2007 and 2009, increasing to 10 since 2010.

Comparing the E&P indicators among these active operators in this region, only three companies have been increasing the well’s productivity in this period: Apache, Pluspetrol, and Petrobras Argentina. Figure 31, below, demonstrates the total production according to company in the *Vaca Muerta* region.

Figure 31 – Production from *Vaca Muerta* according to company between 2007 and 2011



Source: Based on Secretaría de Energía (2020b).

Figure 31 demonstrates that Apache has been substantially increasing its production, followed by Petrobras Argentina and Pluspetrol (another independent company). We highlight that Petrobras Argentina is the Brazilian NOC, initially differing from independent companies' type and risk aversion. In this case, we assume that despite Petrobras is a NOC, it has been acting

as an independent company in Argentina, taking high risks to overcome the technological challenge in the *Vaca Muerta* region.

Another remarkable element is the YPF's difficulties in catching up with the leaders' achievements. We emphasize that in this period (2007-2011), YPF acts as an IOC since its re-nationalization happens only in 2012 (a process explained in section 0). Although YPF increases its investments in the *Vaca Muerta* region, raising the number of active wells from 6 in 2007 to 33 in 2011, its average well's productivity substantially falls, from 25 kcm/d in 2007 to 12.7 kcm/d in 2011. The reduction in its well's productivity decrease the YPF share in the whole *Vaca Muerta* production from 13% in 2007 to 4.8% in 2011 (as previously shown in Table 11).

Considering the heterogeneity in unconventional reservoirs, only after the government plan guaranteeing a minimum price for natural gas, the companies operating in the E&P in *Vaca Muerta* intensify the region's exploitation. Among these companies we emphasize that there are IOCs increasing its investments, however the leading companies accepting the risks related with the technological adaptation are independent, being them the regional leaders between 2006 and 2011.

As emphasized by Dosi (1982) and better exposed in the first section of chapter 2, the first phase concerning the technological introduction is featured by its high risks, demanding a company assuming these risks to appropriate further profits. As in the US case, this role is played by independent companies. Additionally, acting as an IOC (i.e. previously to its re-nationalization), YPF has been presenting difficulties to catching-up with the leaders, demanding time to attain better results.

Thus, we conclude that the productivity peaks of 2008 and 2010/2011 are a result of the quick expansion of the E&P activity after the implementation of the plan Gas Plus in March 2008. Producers focused on increasing the exploitation of the most productive unconventional reservoirs, delimited by the tight ones. This technological adaptation demands a risk-taking company, performed in both cases (US and Argentina) by independent companies.

3.3.3 The second learning curve stage: the productivity peak of 2018/2019 as a consequence of plan Gas III

In Argentina, like the US Barnett shale case, the second learning curve stage is also featured by introducing horizontal drilling associated with a process to catching-up with the leader. Another remarkable similarity is a new leading company, being the previous leader merging with a bigger player. In the US, it is a larger independent company (Devon Energy) that

merges with the leader (Mitchell Energy), while in Argentina is the NOC, YPF that bought the companies leading the first stage (Apache and Petrobras). Finally, the process of catching-up is marked by an increased production associated with a growing number of operators; however, on a different level. In the US, the active operators rise from 18 to 158, while in Argentina, it increases from 10 to 22.

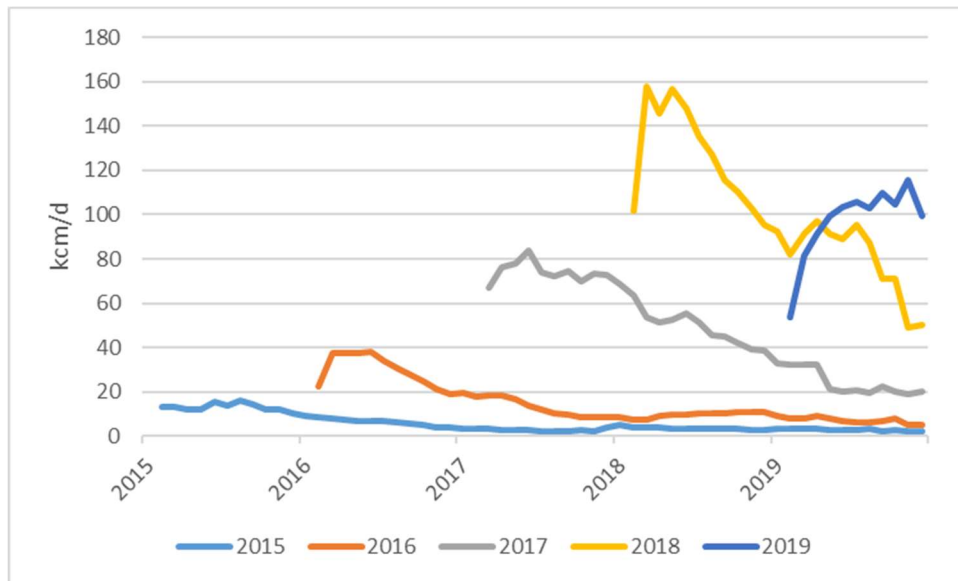
From our analysis of the second learning curve stage, we conclude that differently from the first productivity peak, the 2018/2019 is due to the expansion of E&P activities in unconventional shale reservoirs. In this case, the introduction of the plan Gas III in 2017 (replacing the plan Gas I and II), raise the E&P activity into unconventional shale reservoirs, producing a peak in the well's productivity due to the adaptation of horizontal drilling in unconventional shale reservoirs.

3.3.3.1 The E&P indicators

Sharing the average well's productivity by reservoirs (i.e. on tight and shale), we observe a divergent movement. The well's productivity falls in unconventional tight reservoirs and increases in shale one. In more detail, in unconventional tight reservoirs, it falls between 2017 and 2019 from 31.2 kcm/d to 26.9 kcm/d in 2018 and 23.5 kcm/d in 2019. Conversely, in unconventional shale reservoirs, it increased from 7 kcm/d in 2017 to 23.9 kcm/d in 2018 and 34.2 kcm/d in 2019 (with a peak of 37 kcm/d in August 2019) (Secretaría de Energía 2020b).

The average well's productivity captures the whole wells (new drilling and the legacy wells). Thus, to observe the progress concerning the new drillings, we can split the average well's productivity according to its drilling year. Figure 32, below, demonstrates this data for wells focusing on the *vaca muerta* formation (i.e. unconventional shale reservoirs excluding the tight one) between 2015 and 2019.

Figure 32 - Average productivity from wells of unconventional shale formation considering the year of drilling between 2015 and 2019



Source: Based on Secretaría de Energía (2020b).

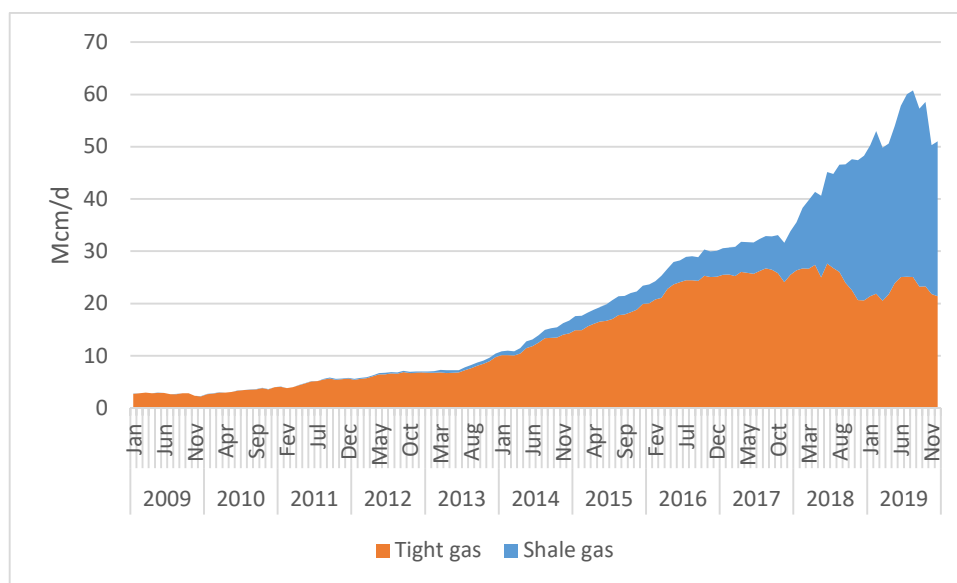
Figure 32 exhibits the progressive increase in the well's productivity in shale reservoirs, starting in 2015 from levels below to 20 kcm/d, substantially increasing in 2016 to 40 kcm/d. In 2017 it overcame 80 kcm/d, and in 2018 it almost doubles, almost reaching 160 kcm/d. Finally, in 2019, it decreases to an average of 100 kcm/d. This substantial increase in the well's productivity between 2015 and 2019 results from the successful introduction of HF and horizontal drilling on unconventional shale reservoirs. In more detail, this increase in the well's productivity coincides with two elements: increasing horizontal well's length; and raising the application of HF method.

Considering the *Vaca Muerta* region average, in 2015, the lateral length of wells drilled in unconventional shale reservoirs achieves 300m, progressively increasing to reach 2 100m in 2019. Concerning the application of HF in the wells length, it increases from 7 in 2015 to 32 in 2019, meaning that, associated with the higher wells' lateral length, operators has been increasing the number of fractures (Secretaría de Energía 2020b).

Finally, after the government direct the price incentive in the plan Gas III exclusively to E&P activities on unconventional shale reservoirs, there is a substantial increase in production from these reservoirs based on the increasing active wells. From an initial number around 700 in January 2018, it continuously increased to 942 in December 2019. In this context, unconventional shale reservoirs became the leading producer reservoirs in the *Vaca Muerta*

region in October 2018, overcoming the tight reservoirs (25 Mcm/d from shale reservoirs while tight reservoirs produced 22.3 Mcm/d) (Secretaría de Energía 2020b). More detail about the regional production according to shale and tight reservoirs are presented in Figure 33, below.

Figure 33 – Monthly average production according to reservoir (shale and tight) in the *Vaca Muerta* region between 2009 and 2019



Source: Secretaría de Energía (2020b).

Figure 33 shows two movements. First, the increasing production from the *Vaca Muerta* region based on unconventional tight reservoirs until 2018. Second, since 2018, the growing production from unconventional shale reservoirs, being the leading reservoir in the *Vaca Muerta* region.

Observing only unconventional shale reservoirs production between 2009 and 2019, it increases faster than unconventional tight reservoirs. Since 2017, shale reservoirs' extractions increased its pace, rising its participation from 17% in January 2017 to 58% in December 2018, keeping this share on the regional production¹⁶⁹.

¹⁶⁹ Observing oil production in Neuquén Basin (i.e. including conventional and unconventional reservoirs) instead of our focus on natural gas, it presents two movements, declining between 2009 and 2017 and growth since 2017. The first movement presents a net reduction in total oil production from 0.25 Million barrel per day (Mbb/d) in 2009 to 0.2 Mbb/d in 2017. After 2017 the oil production starts to increase, achieving 0.23 Mbb/d in 2019. Sharing the production in conventional and unconventional reservoirs, there is a constant decrease in conventional sources (from 0.24 Mbb/d in 2009 to 0.13 Mbb/d in 2019) associated with an increasing production from unconventional sources (from 977 bbl/d in 2009 to 0.1 Mbb/d in 2019), mainly from unconventional shale reservoirs (from 30 bbl/d in 2009 to 0.09 Mbb/d in 2019) (Secretaría de Energía 2020b).

3.3.3.2 The market structure: the YPF leading role

Observing the regional market, similarly from the first learning curve stage, the second one presents a company leading the productivity peak. Different from the first, this leadership is due to YPF. Since the re-nationalization in 2012, YPF substantially increases their investments, mainly focused on unconventional shale reservoirs. Thus, since 2013 YPF has continuously expanded its market share, from 18% in 2012 to a maximum of 65% in 2017, leading the productivity peak of 2018/2019 corresponding to the second learning curve stage.

Observing the whole *Vaca Muerta* production in 2018 and 2019, YPF has led the regional production with a market share averaging 46%. The second company is Tecpetrol, that increases its participation from 18% in 2018, to 25% in 2019. The regional market share considering the *Vaca Muerta* production is shown in Table 12, below.

Table 12 – Market share in production from *Vaca Muerta* region between 2014 and 2019

Companies	2017	2018	2019	Company type
YPF	65.6%	52.4%	40.8%	NOC
TECPETROL	2.3%	17.9%	25.1%	independent
TOTAL	9.0%	8.6%	11.6%	IOC
PAMPA ENERGIA	0%	4.8%	8.1%	independent
PAE	8.8%	8.1%	6.6%	IOC (BP)
PLUSPETROL	3.6%	3.2%	2.9%	independent
CAPEX	1.6%	1.7%	2.1%	independent
EXXONMOBIL	0.4%	0.6%	1.9%	IOC
PETROBRAS ARGENTINA	7.8%	2.3%	0.0%	NOC
Others Companies (<0.5%)	0.8%	0.4%	0.8%	-

Source: Based on Secretaría de Energía (2020b).

Table 12 reveals that YPF has been keeping its leading role in *Vaca Muerta* since 2017. The increasing market share from YPF is a result of two elements associated. First, YPF bought the leading players of the first learning curve stage, Apache and Petrobras. In 2014, YPF bought the E&P rights of Apache Energy in the *Vaca Muerta* region for 852 million dollars. In 2018, YPF bought Petrobras's operations in Argentina, including the E&P rights in the *Vaca Muerta* region. Second, YPF continuously increases investments in the *Vaca Muerta* region, focusing on unconventional shale reservoirs.

According to YPF (2019), since 2016 the commercial exploitation of unconventional shale reservoirs is economically through the association of horizontal wells and the HF method. In this point, higher horizontal length has to be associated with increasing HF stages (YPF 2019, 5). Thus, the company has been progressively augmenting its productivity, rising both HF stages and

horizontal well's length. While in 2015, the average horizontal length of wells drilled on unconventional shale achieved 1 500 meters (m), progressively increasing to 1 800m in 2017, 2 300m in 2018 and, 2 500m in 2019. The average HF stages also increase in this period, from 16 in 2015 to 21 in 2017, 27 in 2018, and 35 in 2019 (YPF 2020, 10; 2017, 12). The company also informs that all these achievements result in a cost reduction related to drilling and completion operations (YPF 2020, 10).

Additionally, from the first stage to the second one, the number of active operators almost double, demonstrating the increasing interest in this region. From the previous ten active operators, this number rises to 22 in 2019. The active operators encompass national and international independent companies (as Pluspetrol, Tecpetrol, Capex, Pampa energy, and Vista O&G) and IOCs (as TOTAL, Shell, ExxonMobil, PAE – a joint-venture including BP, and Chevron).

Unlike the first learning curve stage, where the higher market share of an IOC reaches only 3.8% in 2011 (representing the TOTAL market share shown in Table 11), there is a higher IOC participation in the second stage. Table 12 reveals that in 2019 three IOCs have a market share higher than 1%, achieving 11.6% for TOTAL, 6.6% for PAE, and 1.9% for ExxonMobil. We conclude in the growing interest of IOC on production from unconventional reservoirs of the *Vaca Muerta* region.

This IOCs movement in Argentina is similar to the process of consolidation in the US shale with a significant participation of IOCs. From this consolidation process, we emphasize that companies as BP, Chevron, ExxonMobil, Shell and Total have been exploiting US Basins hosting unconventional shale reservoirs. The IOCs consolidation is made through acquisitions or direct exploration. Exxon and BP increase its participation in shale through acquisition the first acquiring XTO Energy in 2009 and the second purchasing the US shale assets from BHP Group in 2018. The other IOCs follows an organic growth based on exploring key US shale Basins, Shell enters in the Permian Basin in 2012, Chevron acquired land rights in the Permian Basin and TOTAL has assets in Barnett and Utica Basins. Finally, it is interesting emphasizing that Chevron tried to acquire Anadarko Petroleum in 2019 by US\$ 50 billion focusing on its Permian assets. However, another independent company (Occidental) announced a higher offer, supplanting the IOC's offer.

3.4 Chapter Conclusion:

This chapter aimed to examine the Argentinean experience of the development of its frontier zone, *Vaca Muerta*, in light of the US example, mainly based on the Barnett shale case. Similarly to the US case, the increasing production from unconventional reservoirs located in the *Vaca Muerta* region is due to an association between a specific environment and a learning curve. These two elements in conjunction creates the necessary conditions to overcome the technological challenges of a frontier zone, resulting in increased output from unconventional reservoirs, mainly in *Vaca Muerta* region. This success reaches three remarkable outcomes. First, Argentine national production reverses its declining tendency, almost recovering to its historical production level of 140 Mcm/d in 2020. Second, unconventional reservoirs' participation in the national output substantially increases from 2% in 2009 to more than 40% in 2019. Third, Argentina resumes its exports (initially only in the summer season), incorporating a liquefaction facility to export LNG.

This chapter investigated the specific Argentinean context relating to the unconventional reservoirs' development to shed light on its determinants considering the US experience. This investigation is based on the analytical framework considering the contributions of the historical institutionalism and the evolutionary theory (summarized in Figure 5 from chapter 2), focusing on examining instruments and mechanisms dealing with frontier zones' features. In more detail, this examination focused on instruments and mechanisms mitigating both risks - technological and economic - in the frontier zone of *Vaca Muerta*, considering the specific country context. This chapter also compares the Argentinean experience with the US case based on the examination of these instruments, mechanisms, and their implementation contexts, offering an analytical contrast between them.

Similarly to our analysis of the US case, the historical institutionalist approach that focused on long-term trajectories allowed us to identify a sequence of reforms in the regulatory framework, molding a trajectory that lead to market liberalization in Argentina. The price formation gradually moves from a governmental determination to an interaction between supply and demand. Despite this long-term trajectory, we emphasize that Argentina's particular context prevents a complete liberalization from taking place until 2020.

In more detail, the successive economic crises associated with their social side-effects leads the government to continuously subsidize natural gas consumption, limiting full market liberalization. In this complex context, the government aims to gradually reduce subsidies for natural gas prices, leading consumers to face values that are determined by the market forces'

interaction. For this purpose, the government launches two initiatives. First, it creates a spot market based on the previous experience of NBP (in UK), leading the demand and supply interaction to determine the equilibrium price. Second, to reduce the re-distributional effects from eliminating subsidies, it targets an income transfer program for more vulnerable households.

Additionally, the Argentinean government mobilizes two other instruments to handle the frontier zone's risks. The first involves several forms of cooperation between its NOC and private companies through joint-ventures sharing the developing costs in the *Vaca Muerta* region. This cooperation between YPF and private companies is predominantly focused on IOCs, and seeks both funds to develop the area and partners to share its risks, resulting in the acceleration of the region's technological adaptation. Second, the government implements successive energy plans to guarantee a minimum price for natural gas production. Despite these plans initially not focusing on increasing the production from unconventional reservoirs, taking the investor's perspective, it functions as a financial support for the E&P activities in these zones.

Thus, this thesis concludes that both countries utilize similar instruments to deal with frontier zone risks, notably institutional reorganization of the regulatory framework targeting market liberalization, financial support, and cooperation between public and private sectors. Considering the differences between these instruments, we emphasize that they are distinguished mainly because of context, detailed below.

In the US, the institutional reorganization of the regulatory framework gradually moves the price formation to a liberalization, disregarding its distributional effects (from consumers to producers). Conversely, in Argentina, the economic crisis and its social side-effects context limit market liberalization and the subsequent price increase because of the redistribution effects.

Considering the financial support offered, both countries implement measures focusing on increasing the value of the natural gas produced from frontier zones. There is a price differential associated with tax credits in the US case, while in Argentina there is a minimum guaranteed price.

Finally, cooperation has a different nature in these countries, primarily based technological development. In the US case, the technologies to exploit unconventional reservoirs have to be delimited and stimulated, requiring additional investments to certify their economic feasibility. In these conditions, the US government cooperates with companies interested in adapting these technologies to unconventional reservoirs through bridging institutions and supporting R&D related to the defined technological trajectory (HF and

horizontal drilling). Argentina benefits from the US' previous experiences, designating investments to adjust these technologies to the local geological context. In these circumstances, the government's cooperation is made through its NOC, YPF, via joint-ventures focusing on sharing E&P costs.

From the operations of the Argentinean case's mechanisms, we found remarkable similarities with the US case concerning the learning curve stages and the market structure. In both countries, we found a learning curve shared on two stages with similar features.

The first stage corresponds to an adaptation of HF to the local context as a means of reduce costs. In both countries, this stage is led by independent companies, revealing the high risks feature of this stage, primarily associated with the uncertain technological introduction. As previously described in Dosi (1982), the process of introducing technological advancements is marked by high risks, demanding companies be less averse to risks to start the process, precisely the characteristic of independent companies.

In the second learning curve stage, the primary objective is to achieve higher recoverability from shale reservoirs, which involves HF and horizontal drilling methods. This stage is characterized by another company (in the US an outsider) acquiring the previous leader in order to accelerate the catching-up related to increased competition among firms. Compared to the US case, the second stage in Argentina is characterized by a leading role of the state NOC, YPF, as well as substantial participation of IOCs in the *Vaca Muerta* region.

Conclusion

This thesis proposed to analyze the determinants of the development of O&G frontier zones based on unconventional shale reservoirs. We divided this thesis in three main chapters added with this conclusion. The first chapter presented the O&G perspectives associated with a working definition for our frontier zone concept. The second chapter designs our analytical framework based on two economic approaches, the historical institutionalism, and the evolutionary theory. Based on these theoretical support, we investigate the US case of the Barnett shale region, being attentive to the direct and indirect determinants relating to the gradual evolution of the frontier zones based on unconventional shale reservoirs. The third chapter analyses the Argentinean case of the *Vaca Muerta* region, concluding that the determinants of the frontier zone evolution are similar to the US case.

Previously to analyze our object of study, this thesis focused on delimiting the necessity to develop additional O&G resources associated with a working definition for our frontier zones term. In this case, we overview three O&G outlooks, being attentive to the acceleration of the decline rate due to the structural change in the fields' features (increasing participation of unconventional reservoirs and smaller conventional reservoirs). We concluded that even considering a stability in the energy consumption associated with a fast replacement of O&G by other fuels, there is a necessity to develop additional O&G fields. In other terms, comparing the decline rates with the speed that the O&G demand falls, the decline rates are superior, requiring additional investments on O&G fields. This element demonstrates that even considering a scenario of a fast energy transition to low carbon fuels, there are opportunities to supply future O&G demand through the development of frontier zones by governments interested in them.

We defined frontier zone by its high costs, high risks and the technological challenge to reach their commercial exploitation. Our frontier zone definition may encompass both conventional or unconventional reservoirs. This definition is generic, demanding a refinement to delimit instruments and mechanisms enhancing their commercial exploitation. In this case, from this generic definition, we focused on O&G risks, looking to differentiate frontier zones from other O&G areas. We shared the risks in two main categories: market risks and E&P risks.

Frontier zones differ from other O&G areas due to the E&P risks shared on geological and technical-economic. Focusing on frontier zones based on unconventional shale reservoirs, geological risks, mainly connected with the resources' existence are almost inexistent, leading this thesis to concentrate on technical and economic risks. Additionally, from the investor's

perspective, the absence of E&P activities is the main motivator for the high risk in frontier zones, limiting the involvement of private investors in an initial stage. In this case, the acceleration of the frontier zones exploitation demands a government effort to deal with their rough features, mainly the absence of enough knowledge.

In this context, this thesis focused on the dynamics previously to the shale 'revolution', taking a retrospective viewpoint. This standpoint allowed us to identify the direct and indirect determinants leading to the exploitation in frontier zones based on unconventional shale reservoirs in the US and compare this experience with the Argentinean one.

Our investigation about these determinants accords with other authors that both the particular institutional environment and the technological adaptation are essential to explain the successful commercial exploitation (J. Cooper, Stamford, and Azapagic 2016; Zakaria 2019; Dale 2015; GWPC 2009; IEA 2012; Kuuskraa and Guthrie 1995; Stevens 2010; Wang and Krupnick 2013; Anderson 2013; Harper 2008). In our economic perspective, both elements mitigate characteristic risks from frontier zones.

On the one hand, the increase in natural gas prices enhanced the frontier zones' profitability, mitigating economic risks. The increase in natural gas prices is attained through two instruments. First, through a gradual institutional reorganization in the regulatory framework shaping a trajectory to market liberalization (allowing prices to reflect the interactions between supply and demand). Second, through a financial support from the state, that, from the investor's perspective, is similar to increasing natural gas prices.

On the other hand, the acceleration in technological progress is achieved through one instrument associated with two other mechanisms. The instrument is a cooperation between the public and private sectors, while the mechanisms correspond to a learning curve and the company's risk aversion.

Additionally, our case study methodology allowed this thesis to outline the country's particularities, molding the environment of implementation of instruments and actuation of mechanisms. The association of all these elements delimits our object of study: the commercial exploitation of frontier zones based on unconventional shale reservoirs. To structure the analysis of our two case study, we design an analytical framework structured on both the frontier zones features and our theoretical support based on two main economic approaches: the historical institutionalism and the evolutionary theory.

The historical institutionalism approach allowed us to analyze the institutional dynamics of the regulatory framework through a long term perspective. In this context, we focused on the direction of change instead of scrutinizing each reform, obtaining in both cases (US and Argentina) a trajectory leaving to the market dynamics the determination of the natural gas price. This trajectory represents an increasing wellhead natural gas prices, reflecting the tightening between supply and demand in both countries. Additionally, from the investor's perspective, another element increasing the natural gas prices is the financial support. The US financial support is operationalized through tax credits and higher natural gas prices (lasting until the complete price liberalization). The Argentinean financial support is operationalized through a minimum guaranteed price for natural gas.

Thus, we concluded that both instruments (institutional reorganization in regulatory framework molding a trajectory to reflect the dynamics between supply and demand associated with financial support) mitigate the economic risks of frontier zones increasing the natural gas prices. While the first is an indirect determinant, being adopted by governments without an intention to develop frontier zones, the second is a direct determinant. In the US case, the financial support focuses on high-cost zones, including unconventional shale reservoirs. In Argentina, the government progressively evolves its financial support directing the minimal guaranteed price from additional natural gas production (independently of the reservoirs kind) exclusively to the exploitation of unconventional shale reservoirs.

The evolutionary theory enables this thesis to analyze the complex process of introducing a technological advancement in a capitalist economy. In both cases, the mitigation of technological risks is achieved through an acceleration in technological adaptation. We emphasize that Argentina benefits from the previous development made in the US, mainly the successful association between HF based on the SWF method with horizontal drilling. Despite this direct benefit from Barnett shale's previous achievements, the technological adaptation in Argentina is featured by high risks.

Based on the evolutionary literature, this thesis identified two main aspects to investigate. First, the actuation of focusing forces driving the acceleration of the technological trajectory. In this case, according to Rosenberg (1976), prices (in this thesis, natural gas prices) are fundamental to stimulating technological development. However, they are insufficient to offer a complete elucidation of the phenomenon, chiefly the technological advance's sequence and timing. Thus, this thesis identifies two elements as relevant focusing forces directing and accelerating the technological development: problems with natural gas supply (Rosenberg

1976); and the state role (Dosi and Nelson 2013; Dosi 1982). In this context, the analysis of the country context is mainly concerned with problems in the natural gas supply (as shortages or other limitations), and the subsequent government reaction.

Second, two mechanisms accelerate the technological adaptation, mitigating the technological risks related to the introduction of HF and horizontal drilling on unconventional reservoirs: a learning curve and the company's risk aversion. The learning curve represents the mechanism of appropriation for firms introducing technological progress in the capitalist economy, encompassing several dimensions as: the heuristic of research, its cumulateness, and the learning by doing. Thus, the learning curve encompasses the multifaceted process between firms and markets during the introduction of technological advancements in the economic system.

The evolutionary theory studies the uncertain environment relating to the introduction and selection of technological advancements through markets, highlighting the relevance of heterogeneous agents. The uncertainty is due to the absence of guarantees, *ex-ante*, that the engagement in a specific technological development will provide the expected positive results associated with the *ex-post* selection through markets. The association of these elements generates an uncertain environment for firms interested in engaging in the introduction of a technological advancement, molding a rough environment featured by high-risks. In this context, firms with a lower risk aversion (or with higher risk appetite) are more inclined to engage in the learning curve process in a high-risk investment to capture more profits in future.

Based on our analytical framework (showed in Figure 5, chapter 2), this thesis analyzed the two experiences concerning the development of frontier zones based on unconventional shale reservoirs of the US and Argentina. From this analysis, we conclude that the development of these frontier zones presented three main elements. First, the countries analyzed confront problems in natural gas supply triggering a government effort to overcome them. Second, we can share these efforts on two, financial support (increasing the profitability of frontier zones) and a cooperation with private companies (accelerating the technological introduction). Third, companies aiming to engage in an uncertain technological adaptation are less risk averse (mainly represented in the O&G sector by independent companies), engaging in a learning curve to capture higher profits in the future. In our perspective, governments can accelerate this process through direct cooperation with the private sector.

A comparison between the countries analyzed allowed us to conclude that both countries faced a supply problem. While the US faces two successive natural gas shortages amid two oil

shocks, Argentina confronts a supply crisis with social and economic impacts. In the US case, the increasing demand associated with the insufficient supply leads the country to shortages during the winters of 1975-76 and 1977-78. Similarly, in Argentina, the substantial increase in demand overcomes the supply, leading the country to limit demand aiming to surpass the shortage. Since the supply problems, both countries implemented some instruments that initially did not target developing frontier zones based on unconventional reservoirs, however, they mitigate their characteristic risks.

In both countries, the institutional change shapes a long-term trajectory leading to a price formation based on the dynamics between supply and demand. The price formation gradually moves from a governmental determination to an interaction between supply and demand. In the US long-term trajectory, successive reforms prepare for this dynamics in the 1990s. This price formation allows natural gas prices to reflect the tightening between supply and demand, raising natural gas prices before the shale 'revolution'.

The Argentinean particular context prevents a complete liberalization in price formation until 2020. The Argentinean context mainly differs from the US due to successive economic crises associated with its social side-effects. This specific context in Argentina leads the government to continuously subsidize natural gas consumption, limiting an increase in prices (reflecting the tightening between supply and demand) at the same time that reduces the redistribution effects from the natural gas price increase. In both countries, the price increase from this new market dynamic did not target the development of unconventional reservoirs. However, it mitigates economic risks for frontier zones.

Conversely of the increase in prices from the liberalization in natural gas price formation, the financial support is a direct measure aiming to develop frontier zones. In the US case, the government mobilizes tax subsidies (lasting until 2002) and higher natural gas prices (under the price's control period) to accelerate the exploitation of high-cost zones (including unconventional shale reservoirs). In the Argentinean case, the national government creates energy plans to guarantee a minimum natural gas price. From the investor's perspective, these measures operate as financial support for the E&P activities in frontier zones.

Similar to the US case, the Argentinean government creates financial support for companies engaging in the exploitation of unconventional reservoirs. This financial support is operationalized through higher guaranteed prices targeting to increase the national natural gas production from all reservoirs. Nonetheless, the positive results from unconventional

exploitation refine the financial support, directing the guarantee priced exclusively to shale reservoirs.

Both elements, institutional reorganization and financial support increase the natural gas prices, mitigating the economic risks of frontier zones based on unconventional shale reservoirs. Both countries, the US and Argentina, mobilizes these instruments to direct (financial support) and indirectly (institutional reorganization) develop unconventional reservoirs.

Another instrument mobilized by both governments is a direct cooperation with companies engaged in introducing technologies (in this case, HF and horizontal drilling) on unconventional reservoirs. This instrument is a direct effort to develop unconventional reservoirs, focusing on accelerating the technological adaptation, thus, mitigating the technological risks of frontier zones.

In the US case, the government accelerates technological introduction through two main measures. First, it delimits the potential from unconventional reservoirs exploitation, identifying additional national energy sources. Second, associated with the private sector, it defines the technological trajectory relating to the adaptation of both extractive methods (HF and horizontal drilling) to unlock natural gas from unconventional reservoirs. In this particular case, the government provided funds to test both technologies on unconventional reservoirs, debating with private actors the most adaptable techniques associated with other necessary technologies to reach the commercial exploitation of these resources. To reach this objective, the government creates several bridging institutions to attain technological advancements by adapting and creating technologies to unconventional reservoirs.

In the Argentinean case, there is a cooperation between the public and private sectors, however of a different nature than in the US, mainly due to the technological challenge presented in both cases. While the US delimits and advances the state-of-the-art for shale gas technologies, Argentina benefits from these advances. In these conditions, the cooperation is based on the association between the NOC and private companies, mainly IOC's, through joint-ventures sharing the developing costs in the *Vaca Muerta* region. This cooperation between YPF and private companies are predominantly focused on IOCs, searching for both funds to develop the area and partners to share risks, resulting in the acceleration of the technological adaptation in the region.

Thus, this thesis accords with other authors that the technological development in Argentina benefits from the previous US progress, presenting an advantage over the US initial conditions (Wang and Krupnick 2013, 32–33; Morrow 2014, 6; IEA 2019, 378). After the US

experience and the shale 'revolution', frontier zones based on unconventional reservoirs present a technological challenge incorporating the adaptation of the delimited technologies to the geological context. Nonetheless, this is still a significant technological challenge that represents high risks for companies engaging in introducing these advances to capture future profits from the learning curve achievements. In the Argentinean case, these high technological risks are shared between the NOC and IOCs. Thus, both countries directly mitigate technological risks associated with frontier zones cooperating with the private sector to enhance the technological adaptation.

Concerning the mechanisms, based on the evolutionary theory, this thesis identifies and analyzed the operation of two, the learning curve and the companies' risk aversion. We based our analysis of the learning curve considering the wells' productivity peaks as relevant marks to focus our analyses encompassing the market, the environment and the companies involved in the technological introduction. The utilization of the wells' productivity peaks allowed this thesis to share the learning curve on two stages. In both countries, the first learning curve stage is featured by the adaptation of HF in vertical wells. While in the US case this technological adaptation occurs in shale reservoirs, in the Argentinean case it is focused on tight reservoirs. The second learning curve stage corresponds to an association of the HF method with horizontal wells in unconventional shale reservoirs.

Scrutinizing each learning curve stage and the market structure, we found another remarkable similarity among the cases. The first learning curve stage is led by an independent company, notably less risk averse (or with a higher risk appetite) than other O&G companies. This leadership reduces gradually in the second learning curve stage according to the increasing number of companies exploiting the area. In the US case, a larger independent company merges with the leader and, simultaneously, other independent companies start a process to catching-up the leader's achievements. In Argentina, YPF (the NOC), acquire the two leading companies, formalizing several joint-ventures with IOCs to exploit the *Vaca Muerta* region at the same time that other companies increase its participation in the exploitation of this region. We can assume that this increasing participation of other companies represents the spillover effects from the accumulation of knowledge from the learning curve achievements in both cases.

According to Dosi (1982), technological advancements in an economic system generate specific dynamics following two main phases. Concerning this dynamic, the analysis of the introduction of HF and horizontal drilling in both countries, the US and Argentina, reveals an interesting parallel with the evolutionary theory. While in the first phase (emergence) an actor

should accept to take risks for introducing the technological advancement, the second phase (maturity) is featured by oligopolistic competition. From the examination of our periodization of the learning curve from these two regions (Barnett shale and *Vaca Muerta*), we observe these two distinct phases. The first incorporating a leading company (a role played by independent companies, notably less risk averse), and the second is characterized by growing competition among companies. About the second learning curve stage, it is relevant emphasize the consolidation of unconventional exploitation. While in the US the increasing competition is attained through larger independent companies, in Argentina it is notable the increasing participation of IOCs.

From our economic perspective, we agree with other authors that a particular environment associated with a learning curve are the relevant determinant for explaining the growing production from unconventional reservoirs in both countries. Nonetheless, this thesis details each country's particular environment, scrutinizing the learning curve achievements and its multiple feedback with the environment, providing additional lessons for governments interested in developing O&G frontier zones.

We emphasize that a particular contingency drives the countries to increase national production. To attain this objective, the government progressively re-design its environment mobilizing three main instruments (the regulatory framework's reformulations, the financial support and the cooperation with the private sector) to directly or indirectly develop unconventional reservoirs. Despite the mobilization of these instruments, our case study demonstrates the necessity of companies with lower risk aversion to engage in an uncertain learning curve, triggering the first stage. In the Argentinean case, it is interesting observe that the initial operations are focused on tight reservoirs, notably less expensive than shale ones. The association of these three instruments and two mechanisms, in our case study, has been demonstrating the essential elements to reach the commercial exploitation of frontier zones based on unconventional shale reservoirs.

Finally, our comparative analysis allows us to highlight both, similarities and differences in the US and Argentina. Additionally, we emphasize that the specific context of each country has been leading to different development paths. To summarize all these results, we provide Table 13, below, shared in three parties concerning the natural gas context, similarities and differences, encompassing the most relevant elements that this thesis compared between the selected countries.

We also precise that the share from the unconventional reservoirs sources in national production has been growing continuously since the beginning of their commercial exploitation, revealing the relevance of the unconventional shale sources for the national supply in both countries. More precisely, in the US, the extractions from unconventional shale reservoirs achieves in 2018 the remarkable level of 72.1% while in Argentina, in 2019, it achieves 40.3% (item 1.1 in Table 13). Despite the lower relevance in Argentina, the unconventional shale production has been quickly growing in this country.

Concerning the natural gas participation in the energy consumption, historically Argentina has been relying more in natural gas to satisfy its national demand for energy than US. In 2019, 54.6% of all primary energy consumption in Argentina was provided by natural gas while in the US it provided 32.1% of the primary energy consumption (item 1.2 in Table 13). In this case, Argentina relies more in natural gas than the US, being this source of energy responsible by more than 50% of the total country's energy consumption.

Additionally, it is relevant to emphasize that the beginning of the commercial exploitation of unconventional shale reservoirs occurs in a region with a previous O&G activity (item 1.3 in Table 13). In this context, all the necessary infrastructure is already developed in both countries, reducing the initial costs to begin the commercial exploitation.

Table 13 - Synthesis of the comparative analysis

		Item	Elements	US	Argentine
Natural gas context		1.1	Share of the unconventional reservoirs production in the national production	72.1%	40.3%
		1.2	Natural gas participation in the energy consumption	32.1%	54.6%
		1.3	E&P activities in the region	yes	yes
Similarities	1. Country's context	2.1	Reduction in the national natural gas production from conventional sources?	yes	yes
		2.2	Continuous deterioration in the R/P indicator?	yes	yes
		2.3	Natural gas supply crises?	yes	yes
		2.4	Natural gas external dependence starting in	1970s	2010s
		2.5	External issues enhancing the country's sensibility to the natural gas imports	oil embargo	deficit in the balance of payments
		2.6	Production from unconventional reservoirs finished with the external dependency	yes	no
	2. Organizational reforms	2.7	Opening process in the E&P?	yes	yes
		2.8	Increase in natural gas prices from the liberalization process?	yes	yes
		2.9	Minimum price for natural gas	yes	yes
	3. Learning curve characterization	2.10	Stages corresponds to the emergence and maturity [Dosi (1982)]	yes	yes
		2.11	Delimitation of the two phases in the learning curve	yes	yes
		2.12	First stage	adapting HF in vertical wells	adapting HF in vertical wells
		2.13	Second stage	adapting horizontal drilling and HF	adapting horizontal drilling and HF
	4. Leading role features	2.14	Leader presence in both stages	yes	yes
		2.15	Increasing competition in the second stage	yes	yes
Differences	1. Cooperation public-private sectors	3.1	Cooperation between the public and private sectors?	based on the technological development	based on a cooperation between the NOC and private companies
	2. Companies types	3.2	Companies leading the learning curve	exclusively independent companies	independent and NOC
	3. Financial support	3.3	Tax credits for frontier zones?	yes	no
		3.4	Subsidies to accelerate the technological adaptation	yes	no
		3.5	Higher prices for natural gas production from unconventional reservoirs?	yes	partially

Source: Author

Similarities

1. The country's context

The commercial extraction from reservoirs based on shale reservoirs in both countries, the US and Argentina, is a direct answer to supply issues (item 2.1 in Table 13) which in both cases has led to an increase in external dependence.

In both countries, there is a clear reduction in the production from conventional sources (item 2.1 in Table 13) associated with the reduction in the R/P indicator (item 2.2 in Table 13). There is a continuous deterioration in the indicator previously to the exploitation of unconventional reservoirs. Additionally, this indicator achieves levels inferior to 10. In the US, after the "shale revolution" in 2005, this indicator gradually increases to 15 in 2019 while in Argentina it keeps below 10 until 2019.

The association between these elements demonstrate the possibility of exhaustion of national sources to supply the domestic market previously to the commercial exploitation of unconventional shale reservoirs. Additionally, both countries faced national supply crisis in different periods of time. The US faces two successive natural gas shortages during the 1970s while Argentina faces, in 2004, a natural gas shortage (item 2.3 in Table 13). In both countries, the shortages are severe, demanding governments contingencies to reduce consumption and increase production.

In the US, the external dependency starts in 1970s, intensifying continuously until achieves more than 10% in the 1990s. In Argentina, it starts in 2007 (item 2.4 in Table 13).

In both countries, external issues enhance the country's sensibility to the natural gas imports (item 2.5 in Table 13). In the US case, both oil shocks during the 1970s enhances the government sensibility to the energy issues, mainly the energy security. This increasing sensibility moves the government to launch an energy plan focusing on reducing its external energy dependence, including that in natural gas. In the Argentinean case, the external dependence is associated with issues in the balance of payments, reducing the availability of external currency and increasing its economic problems.

In the US case, the natural gas production from unconventional reservoirs gradually reduce the external dependence, finishing with it. In Argentina, the growing production from unconventional reservoirs reduce the external dependence, however, did not finish, until 2019, with the external natural gas dependence (item 2.6 in Table 13).

2. Organizational reforms: liberalization trajectories increasing prices and the attractiveness of the development of unconventional sources based on shale reservoirs

Both countries observed a gradual trajectory to the liberalization (item 2.7 in Table 13). Particularly in Argentina, we can observe this movement associated with a gradual opening of the E&P rights to private companies, ending with the NOC monopoly.

Associated with the trajectory to the liberalization, we also observed increases in natural gas prices in both countries (item 2.8 in Table 13). In this case, the natural gas prices increased after the beginning of the liberalization process, creating an additional stimulus for E&P activities. Relevant to emphasize that this is a direct stimulus for all O&G resources, not restrict exclusively for unconventional reservoirs.

In both countries we observe a minimum price for natural gas production from unconventional reservoirs (item 2.9 in Table 13). In the US case, this begin in 1981 lasting until

1992, achieving higher natural gas prices ranging between 232% in 1981 and 21% in 1992. In Argentina, the minimum price begins in 2008 lasting until 2021. In this point, it is relevant to emphasize that the Argentinean government proposed to keep the minimum price until 2024, bringing it gradually to market prices.

3. In both cases, the development path concerning the commercial exploitation of shale reservoirs are based on a learning curve shared in two stages

Both stages of our learning curve delimitation corresponds to the previous description of Dosi (1982), the emergence and maturity (item 2.10 in Table 13). While the emergence is featured by a leading company more averse to risks, the second stage encompasses the technological mastery and their widespread, increasing the competition among the agents in this sector.

Thus, we arrived to delimit two stages in the learning curve (item 2.11 in Table 13) of the embedded unity of analysis in our comparative analysis of the US and Argentina, corresponding to the Barnett shale and the *Vaca Muerta* region. Both stages are concentrated in reducing costs to enhance the regional profitability. Both stages are delimited by the identification of regional productivity peaks.

The first stage of the learning curve (item 2.12 in Table 13) is featured by the technological introduction focused on adapting the HF method in vertical wells, reducing the costs associated with this technological adaptation. In the US development trajectory, the first stage is featured by the introduction of the SWF approach in Barnett shale, reducing the costs associated with the HF. In Argentina, the HF method is introduced in the *Vaca Muerta* region through the exploitation of unconventional tight reservoirs through vertical wells.

The second stage of the learning curve (item 2.13 in Table 13) is featured by an adaptation of the HF method with the horizontal drilling in both countries. This adaptation seeks to delimit the quantity of HF stages and the horizontal length of the wells, defining the association between these elements that maximizes production minimizing the exploitation costs associated with both technics.

4. The company's leading role features

In both cases, we observe a role for a leading company to adapt the technologies to the local context (item 2.14 in Table 13). In both countries, the two learning curve stages are leading by a specific company focusing on adapting the delimited technologies to the local geological context.

Another remarkable similarity between the countries is the increasing competition among companies during the second learning curve stage (item 2.15 in Table 13). In both countries we observe a gradual reduction in the leading company market share associated with an increasing number of operators in these areas. In our view, the second stage incorporates the catching-up stage associated with the spillovers from the successful technological introduction, associating HF and horizontal drilling in unconventional shale reservoirs.

The main differences

Despite all these similarities between the countries selected, we also can identify important differences. Mainly, these differences are based on elements non-comparable (or more difficult to compare) from economic, political and institutional aspects.

1. The cooperation between the public and private sectors

We note a cooperation between the public and private sectors in both countries despite its different nature (item 3.1 in Table 13). While in the US the cooperation is mainly directed to the technological development, in the Argentinean case it is based on the association between the NOC and private companies. Another time, this can be explained by the difference in the degree of the technological adaptation. While the US had to delimit and develop the technologies, testing and adapting the exploitation, in Argentina it has to be adjusted to the local conditions.

2. Different companies' types in the US and Argentina

Comparing the selected countries, we observe different companies leading the learning curve stages (item 3.2 in Table 13). While in the US case, the leading role is played by independent companies in both stages, in Argentina, the leading company of the second stage is played by its NOC, YPF. Relevant to emphasize that the first learning curve stage in Argentina is played by an independent company established in Texas. Additionally, analyzing the companies type, mainly its risk's aversion, it is relevant emphasize that in the US, both learning curve stages are led by independent companies, notably less risk averse. In Argentina, the first stage is led by an independent company while the second is led by the NOC.

3. Financial support in the US not found in Argentina

While in the US case the tax credits are implemented after the second oil shock by the Crude Oil Windfall Profit Tax Act in 1980, lasting until 2002, in Argentina there are not a tax credit as established in the US for frontier zones based on unconventional reservoirs (item 3.3 in

Table 13). Concerning this particular case, the Argentina's macroeconomic situation could explain this difference between the countries.

Concerning subsidies applied to accelerate the technological adaptation, we observe another difference between the countries (item 3.4 in Table 13). In the US case we identified several government involvements to delimit and accelerate the development of the technological trajectory to commercially exploit unconventional shale reservoirs. In the Argentinean case, we can't identify a government involvement, leading us to conclude that Argentina has been benefiting from the previous technological development made by US in the precedent decades.

Another remarkable difference concerns the higher natural gas prices for producer in both countries (item 3.5 in Table 13). While in both countries the liberalization process allowed a gradual increase in wellhead natural gas prices, we can observe that in Argentina this is a partial movement. While in the US the government are clearly engaged in a liberalization process resulting in higher natural gas prices for producers and consumers, in Argentina, this redistributive movement is avoided, leading only to a partial increase in wellhead natural gas prices associated with subsidies for consumers and producers. Differently from the US, the economic crisis and their social repercussions prevent the government to completely liberalize the natural gas prices, mainly to limit their redistributive effects.

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